COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

THE BERKSHIRE GAS COMPANY	)	**D.T.E. 01-56**

INITIAL BRIEF OF THE MASSACHUSETTS ATTORNEY GENERAL

Respectfully submitted,

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I. INTRODUCTION

Pursuant to the briefing schedule established by the Department of Telecommunications and Energy ("Department") in this proceeding, the Attorney General submits his Initial Brief responding to the Petition of Berkshire Gas Company ("Berkshire" or "Company") for a $ 4.6 million or 9 % increase in gas distribution rates (the "Petition" or "Filing") under G. L. c 164, §§ 1E and 94. In addition to the proposed rate increase, the Company also seeks an opportunity to recover $ 62 million of costs related to the acquisition of its parent company, Berkshire Energy Resources ("BER"), by Energy East Corporation ("Energy East").[1]

After review of the filing and supporting evidence, the Attorney General requests that the Department reject Berkshire's Ten Year Rate Plan ("Rate Plan") and the recovery of any merger related costs. The Company's Rate Plan does not provide any tangible benefits for customers,

[1] Effective January 1, 1999, Berkshire Energy Resources ("BER") became the parent holding company for three affiliates: The Berkshire Gas Company, Berkshire Propane and Berkshire Service Solutions. BG-1, p. 6. On September 1, 2000, BER merged with Mountain Merger LLC ("Mountain"), a wholly-owned subsidiary of the Energy East Corporation ("Energy East"). *Id.* The Company did not seek prior Department approval of the merger with Mountain. Tr. 9, p. 1072. After this merger, Energy East effectively controls all the BER subsidiaries, including the Company, through the ownership and control of BER.

either in terms of providing a reasonable structure for a Performance Based Rate ("PBR") Plan or for the possibility of reduced rates resulting from the Company's acquisition by Energy East. Although particular problems with the individual elements of the Rate Freeze and the Price Cap Formula will be discussed below, the Rate Plan, with its use of a "fictional" test year, only guarantees that the customers of the Company, who now have some of the highest gas distribution rates in the Commonwealth, will experience rate increases for eight out of the ten years of the plan.

Prior to its acquisition by Energy East, Berkshire had only one price increase in the last nine years. Now under the proposed rate plan, customers will not see one penny of benefit from the acquisition. The Rate Plan guarantees that shareholders will retain all the benefits of reduced operating costs. The Company's proposed Rate Plan will cause significant harm to customers and thus should be rejected by the Department.

As is customary in a rate proceeding, the Attorney General will provide his final recommendations concerning the Company's revenue requirements in schedules attached to his Reply Brief.

A. OVERVIEW OF THE COMPANY'S PETITION

On July 17, 2001, Berkshire filed tariffs with the Department seeking to increase its base rates by approximately $4.6 million to be effective August 1, 2001. Exh. BG-1, p. 2. In order to recover the alleged revenue deficiency, the Company proposes to increase distribution rates an average of 9%. The Company's filed rate plan has a proposed period of ten years and contains various features. *Id.* First, Berkshire requested that the Department calculate the Company's revenue requirement as a "stand alone" enterprise to adjust for any costs related to the Company's recent acquisition by the Energy East Corporation ("Energy East"), although the

Company nonetheless seeks permission to recover an acquisition premium. Tr. 9, pp. 1071-72. Second, the Company requested a 31-month rate freeze followed by a Price Cap Mechanism ("PCM") without an earnings sharing component. Third, Berkshire sought to have the Department review the rate plan's performance at the five year mark with the possibility of early termination during the seventh year. Fourth, Berkshire proposed significant rate structure changes: replacement of the seasonal rate design with an annual rate design for residential, small commercial and industrial customers and the introduction of a load factor gas recovery mechanism.

B. PROCEDURAL HISTORY

On July19, 2001, the Department suspended the effective date of the requested rate increase until February 1, 2002, and opened an investigation into Berkshire's proposal. Notice of Inquiry ("NOI"), July 19, 2001. On July 27, 2001, the Attorney General intervened as of right pursuant to G. L. c. 12, §11E, and commenced filing discovery by agreement with the Company. On August 20 and 22, 2001, the Department conducted public hearings at the Pittsfield City Hall and Greenfield High School Auditorium, respectively. On August 23, 2001, the Department convened a procedural conference to establish a schedule for discovery, hearings and briefs. At this conference, the Department allowed the Massachusetts Department of Energy Resources ("DOER") and the Low Income Affordability Network ("LEAN") to intervene as full participants.[2] Due to the large size, complexity and timing of the filing, the interveners, including the Attorney General, were allowed six working days to draft an initial

[2] The Department allowed the Southern Union Company, Western Massachusetts Electric Company, NSTAR Gas Company, Fitchburg Gas & Electric Light Company, Associated Industries of Massachusetts ("AIM") and KeySpan Energy to intervene as limited participants.

brief after the close of hearings under the Department's procedural schedule.[3] Procedural Order, August 28, 2001.

The parties continued to engage in discovery, and on September 28, 2001, the Attorney General designated a cost of service witness, Paul Chernick of Resources Insight, Inc. On October 1, 2001, the Attorney General filed a motion to dismiss the Company's petition for failure to comply with the implementation order for G. L. c. 164, §1E pursuant to *Service Quality Standards*, D.T.E. 99-84 (2001).[4] The Company opposed the motion. Although the Attorney General requested that the motion be addressed on a short order of notice, the motion has not yet been acted upon.

Evidentiary Hearings commenced on October 3, 2001, and continued until November 2, 2001. During the evidentiary hearings, Berkshire presented numerous witnesses, each of whom offered testimony on a variety of topics with a certain degree of overlap. Fourteen days of hearings were originally scheduled, but this number ultimately grew to seventeen. The Department imposed a witness panel approach imposed as the outside witnesses routinely deferred answering questions by claiming reliance on information prepared by the Company's own employees. E.g., Tr. pp. 1883-1884. As a general matter, the Company proposed that the witnesses testify in the following manner: Dr. Kenneth Gordon, an outside consultant, on the PCM plan and the productivity factor; Robert Allessio, president and chief executive office, on policy and the Whately LNG facility; Karen Zink, vice president of marketing and resource planning, on cost of service, rate design and the PCM; John Kruszyna, manager of internal audit

[3] This figure was increased to seven working days upon oral motion of the Attorney General.

[4] The Attorney General's motion to dismiss was joined by the DOER and AIM by letter endorsement.

and taxes, on accounting, cost of service and cast off rates; Jennifer Boucher, rates and planning administrator, on cost of gas adjustment clause ("CGAC") and weather normalization; Paul Moul, an outside consultant, on rate of return for cast off rates; James Aikman, an outside consultant, on depreciation for cast off rates; Paul Normand, an outside consultant, on rate design; and, James Harrison, also on rate design. BG-1, pp. 6-7.

Pursuant to 220 C.M.R. §§1.04 and 1.10(1), on October 11, 2001, the DOER moved to strike the testimony of Dr. Gordon on the specific price cap mechanism proposed by the Company in this Petition citing his lack of familiarity with certain underlying facts necessary to form an expert opinion. Motion to Strike, pp. 5-7, October 11, 2001. The Department denied this motion and the DOER appealed to the Commissioners. This appeal is still pending.

On October 12, 2001, the Attorney General filed rebuttal testimony of Paul Chernick regarding the Company's use of a MBA allocator in the rate design, and the Company initiated discovery. The Company was granted an opportunity to submit a form of surrebuttal testimony by conducting the re-direct examination of James Harrison on arguments raised by the testimony of Paul Chernick. Tr. 15, p. 1728. On November 2, 2001, the Attorney General's rebuttal witness testified and the Department concluded the hearings.

II. STANDARD OF REVIEW

Unlike other recent mergers of Massachusetts utilities, the Department did not review Berkshire's acquisition by Energy East prior to its completion.[5] As a result, the Company cannot

[5] The Department has held that:

> [a]n evaluation of the Rate Plan in a merger context necessitates an examination of those features of the Rate Plan that are intended to

seek the approval of a rate plan in the context of a Department approval merger pursuant to the public interest standard contained in G.L. c. 164, § 96. Berkshire can only attempt a general distribution rate increase under the just and reasonable standard of G.L. c. 164, § 94. Rather than proposing to freeze rates at a level that has been determined by the Department to be just and reasonable, the Company, by this rate filing, seeks higher distribution rates.

In reviewing rate increase proposals by a utility company under G. L. c 164, § 94, the Department must determine whether the proposed rates are just and reasonable.[6] *Berkshire Gas Company*, D.P.U. 96-67, p. 6 (1996). Since incentive regulation acts as an alternative to traditional cost of service regulation, the "just and reasonable" standard of §94 also applies to PBR plans. *Boston Gas Company*, D.P.U. 96-50, p. 242 (1996) (Phase I). "The burden of proving the propriety of a rate increase remains with the utility seeking the increase." *Town of Hingham v. Department of Telecommunications and Energy*, 433 Mass. 198, 213-14 (2001)

> provide for recovery of the costs associated with the merger. Accordingly, in making a determination pursuant to G.L. c. 164, s. 94 whether the rates that would result from the Rate Plan are just and reasonable and in the public interest, the Department's judgment is informed by the G.L. c. 164, s. 96 public interest standard.

BEC Energy / ComEnergy, D.T.E. 99-19, p. 8 (1999). Since the Company, *inter alia*, did not seek either prior Department approval for the merger or a timely request for deferral of the balancing test required by *Mergers and Acquisitions*, D.P.U. 93-167-A, pp. 7-9 (1995) and *BEC Energy / ComEnergy*, D.T.E. 99-19, pp. 7-12 , the standards found in those decisions are inapplicable to the rate case now under consideration. The Attorney General has appealed the merger decisions in *BEC Energy / ComEnergy*, D.T.E. 99-19 and *Eastern Enterprises-Colonial Gas Company*, D.T.E. 98-128 (1999) and frames his arguments, as he must, in this case with the understanding that those Department's orders are enforceable until modified or overturned by the Massachusetts Supreme Judicial Court. As the appeals are still pending, nothing in this brief should be construed as an adverse admission or waiver of any legal or factual argument that the Attorney General may make in the pending appeals.

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citing *Metropolitan District Commission v. Department of Public Utilities*, 352 Mass. 18, 24 (1967); *Wannacomet Water Co. v. Department of Public Utilities*, 346 Mass. 453, 463 (1963). The Company bears the burden to prove each and every element of its case by a preponderance of "such evidence as a reasonable mind might accept as adequate to support a conclusion." G. L. c. 30A, §1(6); *Fitchburg Gas and Electric Light Company*, D.T.E. 99-118, p. 7, n.5 (2001). If the Company fails to carry this burden, the Department must deny the Company's requested rate treatment for the proposed adjustment. *Fitchburg Gas & Electric Light Company. v. Department of Public Utilities*, 375 Mass. 571, 582-583 (1978).

III. THE PROPOSED RATE PLAN

A. INTRODUCTION AND DESCRIPTION OF THE PLAN

There are three main elements to Berkshire's Plan. First, the Company seeks to increase base rates by approximately $4.6 million. Exh. BG-1, p. 2. As part of this request, the Company requested that the Department calculate its revenue requirement on a "stand alone" basis (i.e, as if the acquisition by EE had not occurred) in an attempt to eliminate any savings associated with the Energy East acquisition. This approach allows Berkshire an opportunity to recover merger costs on a going forward basis to the extent that the merger results in actual net savings.[7] Exh. BG-1, pp. 20, 23; Exh. BG-5, p. 3.

[7] In addition to recovering merger expenses through the fictional "stand alone" calculations, the Company also seeks a second chance to recover merger costs and the acquisition premium. If the Department does not accept the rate plan exactly as proposed, then Berkshire will seek to divert savings from the BP portfolio optimization agreement approved in D.T.E. 01-41 from customers to offset merger-related costs. Exh. BG-22, p. 5; Tr. 8, pp. 954-959. The Company also seeks recovery of lost base revenues ("LBR") resulting from the implementation of energy efficiency programs.

Second, the Company is requesting a price-cap mechanism. After the initial rate increase, Berkshire is proposing a 31-month rate freeze. The freeze will also suspend the application of the Service Quality ("SQ") measures.[8] Following the freeze, the rates would be subject to automatic adjustment though the operation of the PCM. At the five year mark the Company proposed a Department review of the plan with the possibility of early termination during the seventh year. Unless terminated, the plan would continue for a full ten years.

Third, the Company is requesting a change in rate design. The Company proposes to adopt a simplified Market Based Allocator ("MBA") as the method of implementing load factor based cost of gas adjustments ("CGA").

B. THE COMPANY'S RATE PLAN IMPOSES A NET HARM TO CUSTOMERS AND IT SHOULD BE REJECTED

The Company's Rate Plan does not provide any benefits for customers, either in terms of providing a reasonable structure for or a PBR or for providing customers with the possibility of receiving reduced rates as a result of the Company's acquisition by Energy East. In fact, the Rate Plan functions to harm consumers.

1. THE COMPANY PROPOSES A RATE FREEZE AT AN INFLATED LEVEL

a. The Company's "Standalone" Cost Of Service Is Not Representative Of Its Actual Test Year Costs, Nor Its Expected Rate Year Costs

The Company proposes to determine its pro forma base rate revenue requirement in this

[8] The Attorney General continues to maintain the that Company did not properly file an service quality plan with the rate petition as required by the Department's order for the reasons already stated in the Attorney General's motion to dismiss. The Attorney General incorporates by reference the arguments on this topic made in section III of DOER's initial brief.

case based on a "stand alone" cost of service. Exh. BG-5, p. 3. That is, the Company seeks to set rates as though the acquisition did not occur. It claims to have eliminated all of the costs and savings associated with its acquisition by Energy East that are reflected in its balance sheet and income statement before it determined the pro forma cost of service. *Id*.

After the rate increase, the Company's plan further provides for a 31 month base rate freeze and then annual rate increases based upon a price cap formula of the inflation rate less a consumer dividend of one percent. Exh. BG-22, pp. 9-10. Although the Company admits that the "stand alone" treatment with the subsequent price cap increases might result in a revenue requirement that is higher than its actual cost of providing service, the Company maintains that this approach is necessary to allow an opportunity to recover the costs of the acquisition. Exh. BG-1, p. 20.

The Department has traditionally set rates based on the costs to provide gas utility service including a return on and of the investment in utility service. As the Department stated in *Incentive Regulation*, D.P.U. 94-158, pp. 3-4 (1995):

> Since the time of its establishment by the Massachusetts Legislature in 1919, the goal of the Department has been to ensure that the public utility companies it regulates provide safe, reliable , and least-cost service to Massachusetts consumers. In seeking to achieve this goal, the Department has traditionally relied on cost-of-service / rate-of-return regulation ("COS/ROR") to determine rates. COS/ROR regulation permits utilities to charge rates that allow them to recover reasonable operating expenses and to earn a fair return on investment.

The Company's Rate Plan fails to satisfy the Department's Incentive Regulation, "least cost" ratemaking principles.[9] Berkshire's "standalone" cost of service treatment creates "phantom"

[9] As in a rate case under G.L. c. 164, s. 94, the burden of demonstrating that a particular incentive proposal is consistent with this standard is on the proponent; a proponent must demonstrate that the proposal is consistent with the Department's goal of "provid[ing] a framework that ensures that the utilities it regulates provide safe, reliable, and least-cost service."

costs to ensure that rates will be higher. The Company characterizes this scheme as creating an incentive for savings, when it is simply a mechanism for increasing rates beyond those that are least-cost.[10]

To be consistent with Department precedent, an incentive plan must "deliver service to customers at lower prices, and encourage innovative services," not simply maintain or increase rates to levels that are higher than rates that are just and reasonable. *Incentive Regulation*, D.P.U. 94-158, p. 53. As the Department has indicated, "[f]irst and foremost, any plan must credibly assign benefits to customers, whether in the form of lower prices or increased service, that improve on what would have been offered under current regulation." *Id.*, p. 54. The Berkshire Plan provides endless rate increases unaccompanied by benefits to customers. Therefore, the Department should remove all of the Company's "standalone" adjustments that cause its cost of service to increase prior to determining a revenue requirement.

b. The Company Did Not Seek Approval Of The Merger With Energy East Nor Did The Department Approve The Acquisition Premium And Other Related Merger Costs

The Company's Rate Plan proposes to recover costs associated with Energy East acquisition of Company's parent, BER. Exh. BG-1, p. 20. These costs include not only the $61 million acquisition but also $5 million in other acquisition related costs. Exh. AG-10-12, p. 2.

The Department establishes rates for utility service under G.L. c. 164, § 94 based on a "just and reasonable" rates. *See e.g. Berkshire Gas Company*, D.P.U. 96-67, p. 6 (1996). The

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Notice of Inquiry at 1, H Mergers and Acquisitions, D.P.U. 93-167-A at 4. *Incentive Regulation*, D.P.U. 94-158, p. 52.

[10] If, as the Company claims, there are savings associated with the acquisition, then these savings have already been created and already exist. Raising rates, therefor, will have no further bearing on these savings, which are already in place.

Company has not met its burden of proof showing that it should be allowed to recover an acquisition premium and acquisition related costs, which represent an amount **greater than the Company's total investment in utility operations**, as represent by its requested rate base in this case. The Company has neither sought a prior determination by the Department of the reasonableness of the acquisition by East Energy nor has it proved that the acquisition costs are reasonable. The Company may, therefore, not recover these amounts. The Company's customers cannot be expected to pay for costs that have nothing to do with the provision of gas distribution service and the Department cannot allow the Company even the opportunity to recover any such costs without a specific finding that the acquisition itself and the amount of costs being sought for recovery were reasonable and necessary. *Id.*

c. The Company Has Not Shown That There Will Be Any Savings As A Result Of the Merger

The Company asserts that there will be savings as a result of its acquisition by Energy East to offset the acquisition premium and acquisition related costs. The Company, however, has not shown that there were any true savings directly related to any synergies associated with the acquisition. Even the Company's cost of service witness, Mr. Kruszyna, could not quantify the expected savings over one year much less the expected savings over the term of the proposed Rate Plan. Tr. 9, pp. 1068-1069. Without any showing that there are savings to offset the expected costs that the Company seeks to recover from its customers, the Department cannot allow recovery of those costs. *North Attleboro Gas / Southern Union*, D.T.E. 00-26, p. 10 (2000).

2. PRICE CAP FORMULA

a. Introduction

The Company proposes as part of its Rate Plan to implement a Price Cap formula that will subject rates to annual increases beginning in September of 2004. The model for the Price Cap formula that the Company proposes in this case is similar, although not the same as those approved by the Department for other utilities Rate Plans. See *Boston Gas Company*, D.P.U. 96-50 (1996) and *NYNEX*, D.P.U. 94-50 (1996). The general formula provides for annual changes to the Company's rates based on the equation:

$$\mathbf{P = I - X \pm Z}$$

where P is the percent change in the overall average rate; I is the rate of increase in costs; X is the rate of change in productivity; and Z are any changes in exogenous costs or benefits, including service quality penalties expressed as a percent of the Company's revenues.[11] Exh. BG-22 and Tr. 14, pp. 1509-1510. The Department should reject the Company's proposed Price Cap formula because Berkshire has provided essentially no evidence to support its proposed productivity factor and has proposed an expansive definition of allowable exogenous costs contrary to Department precedent.

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[11] The Company's formulas indicate that exogenous costs will be added to the Price Cap formula but Ms. Zink, during cross-examination from the Department, clarified that exogenous costs could be either positive or negative depending on whether the increase or decrease the Company's costs. Tr. 3, pp. 291-292.

b. Inflation Index

The inflation index that the Company has chosen for its proposed Price Cap formula is the Gross Domestic Product Price Index ("GDPPI"). Exh. BG-22, pp. 11-12. The GDPPI is a widely used, objective measure of inflation in the economy that is published by the federal government. *Id*. The GDPPI is the same index used by the Department in each of the Price Cap formulas it has approved to date. *Boston Gas Company*, D.P.U. 96-50, p. 273 (1996) and *NYNEX*, D.P.U. 94-50, p. 141 (1996). Consistent with precedent, if the Department were to approve a Price Cap formula, it should continue to use the GDPPI as proposed by the Company.

c. The Company Has Not Provided Any Support For Its Proposed Productivity Factor

The Company proposes to include its Price Cap formula with a productivity factor or X-Factor of one percent. Exh. BG-22, pp. 12-13. The Company sponsored the testimony of Mr. Kenneth Gordon, a consultant who testified about the appropriate productivity factor. Exh. BG-3, pp. 21-24. Mr. Gordon based his analysis in this case on the studies and analysis contained in a prior Department proceeding concerning Boston Gas Company's Price Cap Plan. *Boston Gas Company*, D.P.U. 96-50 (1996). Exh. BG-3, p. 22. Mr. Gordon's testimony, however, does not provide the Department with substantial evidence to support the proposed productivity factor. To the contrary, the evidence indicates that the productivity factor for Berkshire should be much higher than the factor the Department set for the Boston Gas Company.

The Department should note that Mr. Gordon is not an expert witness regarding the magnitude of productivity factors to be used in Price Cap plans for gas utility companies. He admitted during cross-examination that he has never in his career performed a productivity study for any gas distribution company.[12] Tr. 1, pp. 23-24. The Department, therefore, should give Mr. Gordon's testimony little weight and his testimony should not be the basis of a Department decision on this issue. More importantly, neither Mr. Gordon nor any other Company witness performed a Berkshire specific productivity study. Tr. 1, p. 23. Mr. Gordon and the Company merely rely on the analyses and results from the 1994 Boston Gas Company studies. The Boston Gas studies, by themselves without any further analysis, are insufficient to provide an evidentiary basis to support an appropriate productivity factor for Berkshire.

Three elements critical to the Boston Gas record are absent in this case. First, Boston Gas Company sponsored the testimonies of two expert witnesses who actually performed studies to measure the productivity of Boston Gas operations. *Boston Gas Company*, D.P.U. 96-50, p. 264, n. 120 (1996). Rather than relying on conjecture or broad-brush stroke assumptions, Boston Gas company actually had experts perform a quantitative analysis with statistics. *Id*., pp. 271-273. Second, one of the most important analyses performed by those witnesses was to show that Boston Gas operations were as productive as those of other comparable gas distribution companies. *Id*., pp. 274-279. If the utility is not as productive as other similar companies, then using an industry productivity factor without some adjustment would be counter productive, since it would allow the utility to continue its inefficient ways. Finally, Boston Gas used all of the data available in its productivity studies, including the most recent information it could find. *Id*.

Berkshire Gas Company, on the other hand, has failed to provide any of these three critical elements. First, it did not perform any quantitative analysis regarding its productivity.

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[12] Neither has Mr. Gordon performed a productivity study regarding the telephone industry in which he started his career. Tr. 1, p. 15.

Second, the Company has failed to show that its productivity is comparable to that of Boston Gas Company or the gas distribution companies in the North East United States. Third, Berkshire failed to update the study for the most recent information available.

These failures by the Company are significant, emphasizing the impropriety of simply adopting the Boston Gas factor. The Company has some of the highest rates for gas transportation service of any of the gas utilities in the Massachusetts. Tr. 2, pp. 185-186. Allowing a productivity factor equal to that of Boston Gas would permit the Company to extract uneconomic rents for its customers. Updating the Boston Gas study for the information through year 2000 (the Boston Gas study covered the period 1984 to 1994), would increase the number of years of data being studied by 50 percent. Importantly, the authors of the Boston Gas Study themselves recognized the importance of performing an update to the study at the end of their rate plan in 2001, in order to adjust for the changing environment. Exh. AG-3.

Berkshire Gas Company has failed to meet is burden of proof. There is no credible evidence in the record to support the use of the same productivity factor for Berkshire that the Department set for Boston Gas Company. To the contrary, given Berkshire's relative inefficiency, the Company should have a higher productivity factor than Boston Gas to correct for the inefficiencies built into its cost of service and rates.

d. The Exogenous Costs Should Conform To Department Precedent

The Company's proposed Price Cap formula includes an adjustment to rates for exogenous costs. The exogenous costs are generally defined as the costs that are outside the Company's control and that do not effect the economy in general. *Boston Gas Company* D.P.U. 95-50 (Phase I) , p. 292 (1996). Specifically, the Company proposes to define exogenous costs as costs that are in aggregate annual revenue requirement amounts of $50,000 (with inclusion of individual items over $10,000) and are in the following areas:

(1) Accounting, legislative, regulatory or tax changes;

(2) An "act of god" (force majeure);

(3) Changes in Demand Side Management Policy; and

(4) Lost base revenues not recovered through the rolling period method.

Exh. BG-22, pp. 13-14. The Company's proposed exogenous cost definition greatly exceeds the definition of exogenous costs adopted by the Department in the other rate plans it has approved for other Massachusetts utilities. Accordingly, the Department should reject the Company's expansive definition.

The Department has been consistent in the definition of exogenous costs included in the many rate plans that is has approved prior to this case. *NYNEX*, D.P.U. 94-50, pp. 172-172 (1995); *Boston Gas Company* D.P.U. 95-50 (Phase I) , p. 292 (1996); *Bay State Gas Company*, D.T.E. 98-31, p. 17 (1998); *Essex Gas Company*, D.T.E. 98-27, p. 19 (1998); *Colonial Gas Company*, D.T.E. 98-128 p. 55 (1999). In Boston Gas Company, D.P.U. 96-50, the first decision regarding a gas distribution company, the Department found the exogenous costs that should be included in a price cap formula should include the following:

> [E]xogenous costs shall be defined as positive or negative changes actually beyond the Company's control and not reflected in the GDP-PI, including, but not limited to, cost changes resulting from:
>
> - changes in tax laws that uniquely affect the local gas distribution industry;
> - accounting changes unique to the local gas distribution industry; and
> - regulatory, judicial, or legislative changes uniquely affecting the local gas distribution industry.

> As stated above, proponents of exogenous cost recovery will bear the burden of demonstrating that the costs were (1) beyond the company's control, and (2) not reflected in the GDP-PI. Finally, the Department rejects the Company's proposal that exogenous costs in a particular year be considered on a cumulative basis when determining whether the $500,000 threshold was exceeded.

Boston Gas Company D.P.U. 95-50 (Phase I), pp. 291-292 . The Company has not provided any new arguments or any new evidence that should cause the Department to reconsider or change its well-founded precedent with regard to exogenous costs. Reasoned consistency requires that the Department continue to use the same definition of exogenous costs for as it has for all of the other rate plans if it is to approve any price cap formula for the Company in this case. *Boston Gas Company v. Department Public Utilities*, 367 Mass. 92, 104 (1975).

IV. REVENUE REQUIREMENT

A. REVENUES

1. THE DEPARTMENT SHOULD DENY THE COMPANY'S PROPOSAL TO ADJUST TEST YEAR REVENUES FOR ANTICIPATED CHANGES IN RATE DESIGN

The Company proposes to reduce test year revenues by $54,344 for an anticipated change rate design. Exh. BG-6, Schedule JJK-22, Exh. BG-25, p.7. The proposed adjustment reflects the Company's anticipation of moving these customers off of rates Q-42, Q-43, Q-52, and Q-53 which have been closed to other comparable rates. *Id*. The Department should reject the Company proposal because these anticipated rate changes do not negate the fact that the Company did in fact collect those revenues during the test year.

The adjustment to test year revenues is simply a change associated with the rate design for the Company's transportation services. There is no increase in the deficiency, no increase in the revenue requirement and certainly no extra-ordinary change in the customers or usage levels that would qualify this revenue adjustment under the Department's standard. *Fitchburg Gas & Electric Light Company*, D.T.E. 99-118, pp. 16-17, 22 (2001). The change is simply a rate design modification, and, as such, should be reflected in the allocation of costs among rate classes and the billing determinants used to set rates. Any changes in revenues associated with changes in rate design, therefor, should be provided for in the Company's cost allocation study , reflected in the affected classes bill determinants, and not in its revenue requirement determination. The Department, then, should deny the Company's proposed adjustment to reduce test year revenues by $54,344.

2. The Proposed Test Year Revenues Should Reflect The More Accurate Measure of Unbilled Revenues Than The Company Determined

During the test year in this case the Company changed the methodology that it uses to account for unbilled revenues. Exh. BG-5, pp. 27-28. Prior to the test year, the Company only recognized on its financial statement revenues associated with gas service for usage that it had billed its customers. *Id*. Beginning with its calendar year 2000 financial statements, the Company began to recognize revenues associated with gas service that it had provided to customers, but for which it had not billed – unbilled revenues by making a rough estimate of those revenues.[13] *Id*. This change in accounting caused the revenues in the one year of change-over to be abnormally high, since they included both the unbilled revenues associated with the previous year as well as the unbilled revenues associated with the current year. *Id*. The Company proposes to reduce test year revenues by $609,173 to remove its estimate of the

[13] The unbilled revenues occur at the end of the reporting year – December in the case of Berkshire. Exh. BG-5, pp. 27-28

unbilled revenues associated with service provided before the test year. Exh. BG-6, Schedule JJK-35.

The Department should reject the Company's proposal to use its rough accounting estimate of the unbilled revenue instead use the more accurate measure that was provided in the evidentiary record in this case. The measurement of unbilled revenues was required in order to comply with the Company's auditor's request to provide a better estimate of the reporting year's revenue. Exh. DTE-1-23(a). The Company made a rough estimate to comply with that accounting requirement. Exh. DTE-1-23. Here, however, the Department has before it more accurate amounts that better reflect the billing cycles that the Company actually incurred and that can be used to produce a revenue level more representative of actual test year revenues. Exh. DTE-RR-37.

Specifically, the Department should replace the rough estimate of test year end unbilled revenues of $701,000 with the more accurate figure of $1,008,437 and replace the test year beginning unbilled revenues of $609,173 with the more accurate figure of $737,432. *Id.* and Tr. 14, pp. 1596-1598. These adjustments to unbilled revenues will increase the Company's pro forma revenues by $179,178:

$$[(\$1,008,437 - \$701,000) + (\$609,173 - \$737,432)] = \$179,178.$$

Id.

B. RATE BASE

1. WHATELY LNG PLANT ADDITION

a. The Whately LNG Plant Is Not Used And Useful

The Company proposes to include in its rate base a new LNG facility it had built in Whately, Massachusetts in its Greenfield Division (the "Whately facility") and placed in service at the beginning of the test year. The Whately facility, which includes a large tract of approximately 16 acres of land sufficient to build seven LNG tanks, has an original cost of $5 million. The Company completed construction of two LNG storage tanks, injection facilities and other necessary equipment, and may begin construction of a third permitted tank in the near future. During the test year the Company began the operation of the constructed facilities. The Company suggests that the facilities are simply there to maintain pressures on the Greenfield Division system and meet future system demand. BG-1, p.11 and Tr. 2, pp. 177-182. The Attorney General, however, disagrees with the Company's proposal to include the LNG facilities in rate base.

The Department's standard for inclusion of plant in rate base is found in *Western Massachusetts Electric Company*, D.P.U. 84-25 (1984). To promote cost-effective investment decisions by utility management, the Department uses the "used and useful" standard:

> The regulatory standard which meets the Department's goals of promoting efficient utility planning is the used and useful standard. "Used" under this standard requires that the given investment be in service and operating to provide benefits to customers. "Useful" under this standard requires not only that the investment be used, but also that it be needed and economically desirable in providing continuing service to customers. For electric utilities, this means that, to be included in rate base, the investment must provide either capacity which is required by the utility, [Text Footnote:] (We include in this definition a level of capacity needed for reliability considerations as well) or energy at a net cost which is lower than

> the cost of the energy which it displaces.
>
> The "useful" element means that the used and useful standard in not an all-or-nothing determination. That is, there are different degrees to which a plant may be useful, and the standard allows a continuum of investment recovery and return. For example, if a utility plant, while used, was of larger capacity than required to meet its load and reserve requirements and provided no net energy savings, the portion of plant which would be recoverable and allowed to earn a return would be that portion which the Department found was useful, i.e., provided benefits to the utility's customers.

Id., pp. 40-41. Thus, the additional LNG capacity that the Company proposes to add to rate base must be needed and economically desirable. The record in this case shows that the Company has capacity more than 40% in excess of its design needs and, to the extent that the LNG facilities contribute to the excess and have not been shown to be more economic than any other capacity source, the Department should disallow the full recovery of the associated costs.

b. Excess Capacity

The Company's proposed addition of the Whately LNG facilities does not meet the Department's used and useful standard. The Company has not shown that it needs the increment of capacity provided by the Whately facility for reliability on the system or to meet the growth in demand during the rate year. As Mr. Chernick explained:

> The capacity available on the Company's system appears to be vastly surplus to its current needs. The LNG facility was built at least in part to "provide supply margins for growth well into the next century." (AG-1-9, Remarks of Scott S. Robinson President and CEO at the Berkshire Energy Resources Annual Meeting of Shareholders, November 4, 1999). The current surplus must be taken into account in determining whether the costs of the LNG facility should be fully recovered and how they should be allocated among rate classes.

Exh. AG-7, pp. 20-21. During the course of these proceedings the Company's witnesses were asked to explain the apparently excessive level of capacity reserve highlighted in Mr. Harrison's schedules and workpapers. According to data supporting Mr. Harrison's calculation of the load factor CGA allocators, year the Company paid for 61,764 Mcf of capacity during the test while its design day requirements were only 43,842 Mcf–indicating a reserve margin of 17,922 or more than 40%. Exh. BG-20, Schedule JLH-3, p. 7; Exh. BG-21, Workpapers, Schedules JLH-3, pp.6, 18 and JLH-4, p. 117. Mr. Harrison was asked on two different occasions to explain this excess. Both of his responses vaguely referred to the inclusion of capacity that would not be available during design conditions, such as "firm spot" capacity. Mr. Harrison also pointed out that propane capacity was included and that, because the facilities had been almost completely depreciated, this was a very cheap capacity source. Furthermore, he claimed that he did not have the capacity numbers in his calculations for anything other than the assignment of pipeline capacity costs to the base use component in developing the CGA allocators, implying that these figures may not be valid. Tr. 6, pp. 744-746 and Tr. Vol. 15, pp. 1701-1704.

In response to the Attorney General's record request, the Company provided details supporting the calculation of the 40% capacity reserve; a "corrected" tally of capacity for the Company's dispatch model; and the test year capacity figures for two periods: January through March when Penn York Storage capacity was available and April through the year-end without the Penn York Storage. AG-RR-50. This response shows that the Company's own calculations indicate a reserve in excess of design day requirements of 25% at test year end. However, this reserve calculation appears to significantly understate the LNG capacity. Although Mr. Harrison testified that the LNG capacity was set by the Company at 3,100 Mcf in order to maintain a storage level comparable to 3 days of use, the actual capacity of the tanks is between a "theoretical" capacity of 15,000 Mcf to the total level used in Mr. Normand's "pressure support" workpapers,10,000 Mcf. Tr. 15, pp. 1688-1689 and Exh. BG-18, Workpapers, p. 136. If the 10,000 Mcf capacity level were to be used, the Company's reserve in excess of design day requirements would be more than 40%.[14] This lack of clarity is particularly bothersome given the subjectivity and judgement that produces the capacity data for the Company owned facilities. In determining the LNG capacity available to serve the design day requirements the Company decided that it would need to have 3 days of supply available–however, the Company did not provide any data to show that this was a reasonable requirement or how many hours LNG could flow under this requirement. The propane capacity determination is even murkier–although the total propane capacity appears to be 63,600 Mcf (Normand's Workpapers, p. 136) , the capacity included in the dispatch model is between 13,800 and 12,212 Mcf (original and corrected) and Mr. Harrison's marginal cost study "Supply Capacity for Pressure Support" workpaper indicates the propane (LP-air) capacity in 2000/01 was 14,000 Mcf (Total minus LNG), apparently supporting the 13,800 rather than the 12,212 figure. AG-RR-50. Given the variety of capacity data presented, it is reasonable to conclude that the Company has significant excessive reserve capacity for which its customers are being asked to pay.

c. Reliability Requirements

The Company's claim that the LNG facilities are needed for pressure support may be valid; but the extent to which the facilities are currently needed to fulfill this requirement appears to be overstated. The Company did not provide any hard reliability deficiency data or

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[14] Furthermore, the propane capacity level also appears to be understated according to Mr. Normand's pressure support workpaper. The "LP-Air Plants'" capacity is 13,800 Mcf, coincidently the value appearing in the original dispatch model data. AG-RR-50. There is no explanation of why the "corrected" dispatch model used a lower figure for the propane capacity.

even a pressure study in its original filing to support their claim. When questioned about the need for the LNG facility solely for reliability reasons in view of testimony that previously the pressure support had been provided by compressor stations augmented on a couple of days a year by a truck mounted vaporization facility, the witnesses could not point to any economic analysis supporting the LNG alternative to either additional compression facilities or continued use of portable vaporization facilities. Tr. 7, pp. 835-837. Apparently these alternatives were not examined in the LNG siting case, either. According to the decision in that case the alternatives presented were the LNG facility, a pipeline extension, increased interstate pipeline pressure, and the construction of new propane facilities. *Berkshire Gas Company*, EFSB 99-2/ D.T.E. 99-17, pp. 19-21 (1999). In its decision the Siting Board determined that the alternative involving increasing the interstate pipeline delivery pressure was the most economic alternative, but that the lead time would not make this alternative available until the winter of 2002/2003 while the need for relief was in the 1999/2000 heating season[15]. *Id.*, pp. 22-23.

It was only in response to a Department record request to update a previously submitted pressure study that the Company provided evidence was provided regarding the usefulness of the facilities. According to the response (filed on November 7, 2001), the LNG facility would be dispatched on 31 days during a design year. Of these 31 days, the dispatch was needed for supply purposes on only 5 days and the response indicates that the level of supply requirement could be handled by the propane facilities. What the response does not show is what portion of the remaining dispatch (apparently the dispatch deemed necessary to maintain pressure) could be handled by propane and the continued use of portable LNG facilities or

[15] The Company developed the pipeline alternative was developed at the request of the Siting Board; it had not analyzed this alternative as part of its least cost planning process.

expansion of the Company's load management service[16]; nor does the record provide any economic analyses of any alternatives. Again, the record in this case simply does not support the inclusion of the LNG facilities' costs in the Company's proposed rates and the Department should not depart from its precedent to allow such recovery.

Until the Company can provide the required evidence that the LNG facilities are indeed used, useful and provide an economic benefit, the Company may be able to off set some of the costs associated with its investment through the provision of balancing services or discrete supplemental, peaking services to its transportation or interruptible customers. Commodity costs of LNG supplies dispatched to serve load may be recovered through the CGA as the Company has done in the past; but the Company should be cautioned that the dispatching of its LNG supplies will be scrutinized in the context of the CGA filings to determine that the dispatch was based on the least cost alternative.

2. THE COMPANY'S OLD LNG EQUIPMENT IS FOR SALE AND SHOULD BE REMOVED FROM RATE BASE

The Company has included both its new Whately LNG facility as well as the old LNG equipment in plant in service used to determine rate base in this case. Exh. BG-14, Schedule of Indicated Remaining Life Accrual Rates, page 1. In fact, the Company currently has the old facilities up for sale. *Id*., (Letter Report Presenting Findings of the Property Under Study, page 7.) Clearly, the old plant is no longer used and useful and should be removed from rate base. *Id*. The Company has no further need for the unit and plans to sell it withing the year. *Id*. According to the Company's records, the original cost of the plant is $703,516 and the

[16] Under this tariffed service customers agree to reduce their load under certain conditions and, in turn, the customers receive a payment for this flexibility. The Company currently has one large load management customer.

balance of accumulated depreciation is $430,285. Exh. BG-14. Therefore, Department should remove the old LNG facilities from plant in service and reduce rate base by $273,231.

3. The Company Allocation Of Propane Business Costs To Berkshire Propane, Inc. Does Not Conform To The Department's Affiliate Transaction Regulations

Berkshire Gas Company owns and operates propane storage and injection facilities. These facilities are shared with its unregulated affiliate, Berkshire Propane, Inc. Exh. BG-5, p. 14. The Company proposes to allocate 95 percent of the costs of its propane utility plant in service to its affiliate Berkshire Propane, Inc. *Id.* The Company's basis for the determination of the amount charged to Berkshire Propane is the historical embedded costs of the plant.[17] *Id*. citing Exh. BG-15.

The Company's transactions with its affiliates are governed by the Department's regulations. Specifically, 220 C.M.R. § 12.00 requires that a utility must charge the **higher** of book value and market value for all transactions with its affiliates. This requirement applies to all regular business transactions as well as any transfers of assets to the affiliate. The Department reaffirmed these regulations for the Company when it approved the Company's formation of the Berkshire Energy Resources, Inc. which separated the bottled propane business into its own separate corporation. D.T.E. 98-61/87, pp. 19-20 (1998).

[17] The net book value of the propane plant allocated to Berkshire Propane, Inc. is as follows:

	Total	Allocated to Berkshire Propane
Propane Plant In Service	$837,046	$795,194
Accumulated Depreciation	522,776	496,637
Net Book Value Of Propane Plant	$314,270	$298,557

Exh. BG-7, Supplemental Schedule NU-E "Non-Utility Allocations – Propane Tanks (40 year life)."

Berkshire has failed to comply with the Departments regulations and charge the value of its propane plant to its affiliate at the higher of market and book value as is required by the Department's regulations. *Id*. The Company only allocated the net book value of $298,557 of propane plant to Berkshire Propane, Inc. However, the market value of the Company's propane plant is significantly higher than the historical net book value of those assets. The market value as represented by the recent acquisition price of the utility distribution Company is equal to approximately 287 percent of the book value of the business.[18] Exh. AG-10-12 (market value and book value of the Company's assets). Therefore, instead of allocating the lower net book cost of the propane assets to its affiliate, the Company must allocate the higher market value which represents 287 percent of that book value or $856,859 ($298,557 x 2.87). The Department should reduce the Company's plant in service by $856,859 instead of $298,557 to charge the full market value of the propane plant to Berkshire Propane as required on the Department's regulations.

C. WORKING CAPITAL LEAD / LAG FACTOR

1. The Company Has Overstated The Billing Lag In Its Cash Working Capital Allowance

The Company prepared a lead / lag study to determine the lead / lag factor that it would use in determining its cash working capital requirement for base rates and for its Cost of Gas Adjustment Clause ("CGAC"). Exh. BG-25, pp. 3-4 and Exh. BG-26, Schedule JMB-4. The

[18] The net book value of the Company before the acquisition of Berkshire Energy Resources, Inc by Energy East was approximately $33 million. Exh. BG-23, p. 5 and Exh. BG-6, Schedule JJK-14, p. 2, line 10. The allocation to Berkshire of the purchase price in excess of common is $61.7 million. Exh. AG-10-12, p. 1. The total purchase price associated with gas distribution business is $94.7 million ($61.7 million + $33 million) and the market value to book value ratio associated with the acquisition is approximately 2.87 ($94.7 million / $33 million) or 287 percent of net book value.

revenue lag factor that the Company has determined is based on the sum of three periods: (1) the meter read lag – the average time between when service is provided and the meter is read of 15.25 days (Exh. BG-26, Schedule JMB-4, p. 8); (2) the billing lag – the average time between meter read and the mailing of bill was 4.25 days for firm customers and 5.1 days for non-firm customers (Exh. BG-26, Schedule JMB-4, pp. 9-14); and (3) the payment lag – the average time that it takes for customers to pay their bill after it has been put in the mail, calculated by the Company by determining the average number of days payments associated with the Company's accounts receivable balance during the test year (Exh. BG-26, Schedule JMB-4, p. 15).

The Company's study in this case inflated its revenue lag by double counting the billing lag. Mr. Allessio indicated, when the meter reader brings the raw meter information from the daily meter read into the Company each day, the information is immediately loaded into the Company's computer system.[19] Tr. 2, pp. 173-175. The information is converted by the computer systems into the billing and accounting systems. Id., and Exh. AG-RR-2. However, as Mr. Allessio explained, since Berkshire's billing and accounting systems are integrated, the bill should be entered into the Company's accounting system essentially at the same time that the van returns from the field each day and the computer disc with the raw data is entered into the computer system, resulting in an accounts receivable. Thus, the 4.25 days "billing lag" as measured by the Company should not exist, since the automatic meter reading allows for instantaneous conversion of the raw meter data into the accounting system and the accounts receivable from which the Company has measured the customer payment lag and the

[19] Berkshire has Automatic Meter Reading available on 95 percent of its system which allows a van to drive through the streets of the Company's service territory and by radio signals, read the meters of its customers. Tr. 2, pp. 172-176. The raw data is then stored in a computer for later conversions into the Company's billing system. *Id.*

Department should remove the Company's billing lag from its determination of the Company's net lead/lag days that it uses to determine the cash working capital allowance for both base rates and purchased gas expense.

D. DEFERRED INCOME TAXES

1. The Company Has Improperly Treated The Deferred Income Taxes Associated With Contributions In Aid Of Construction

The Company has included an accumulated deferred income tax debit of $186,964, increasing rate base, associated with Contributions In Aid To Construction ("CIAC"). Exh. BG-6, Schedule JJK-29, line 27. Mr. Kruszyna recognized that this amount represents a prepayment of taxes associated with CIAC payments made by certain customers as required by the Company that should not be charged to all of the Company's customers as a rate base addition. Tr. 4, pp. 519-521. The Department should reduce rate base by $186,964 to remove the prepayment of taxes associated with Contributions In Aid To Construction.

E. COSTS OF SERVICE

1. Wages And Salaries

a. The Company's 2001 Management Salary Increases Are Not Reasonable

The Company proposes to adjust its test year cost of service by $ 29, 500 or 11.7 percent increase in officers and directors salaries for 2001. Exh. BG-6, Schedule JJK-8. The Company provided neither testimony nor a study to support the magnitude of the increase.

The Department's precedent requires that wage increases for non-union employees be reasonable and in line with similar utility employees of other companies. *Boston Gas Company*, D.P.U. 96-50 (Phase I), p. 42 (1996) citing *Fitchburg Gas & Electric Light Company*, D.P.U. 1270/1414, p. 14 (1983). In deciding the propriety of prospective non-union wage adjustments, the Department applies a three part standard. *Id*. To meet this standard, a company has the burden of demonstrating (1) an express commitment by management to grant the increase, (2) an historical correlation between union and nonunion raises, and (3) an amount of increase that is reasonable. *Id*.

The Company has not met either the second or the third parts of the Department's test. The Company's study showing the history of wages and salary increases did not show any correlation between the union and nonunion employees that would support an 11.7 percent increase.[20] See Exh. BG-7, Supplemental Schedule D. In fact, the Company's proposed increase for union employees is only 2.75 percent. Exh. BG-6, Schedule JJK-8. Furthermore, Company did not provide a study showing that the 11.7 percent increase is reasonable. Given the magnitude of the union increase at 2.75 percent and the general rate of inflation in the economy is less than 2 percent, one can only conclude that the11.7 percent proposed increase is unreasonable. Id. and Tr. 14, pp. 1567-1568. Therefore, the Department should deny the Company's proposal to increase the cost of service for a 11.7 percent increase officers' and directors' salaries.[21] In the alternative, the Department should limit any increase to the cost of

[20] The table of wages in Exhibit BG-7, Supplemental Schedule D shows that Executive salaries increased during the last nine years at an average annual rate of 9.10 percent:

$$[(3.93 + 13.31 + 6.25 + 3.90 + 5.71 + 13.26 + 18.97 + 6.68 + 9.88) / 9 \quad = \quad 9.10$$

while union employees only received an average annual increase of 2.92 percent during the same period:

$$[(4.00 + 4.00 + 4.00 + 0.05 + 3.00 + 3.00 + 3.00 + 2.50 + 2.75) / 9 \quad = \quad 2.92.$$

[21] The proposed increase in salaries for the year 2001 also affects the proposed increase in those salaries for the year 2002. Exh. BG-6, Schedule JJK-8. To the extent that the Department reduces the Company's proposed 2001 increase, it must make a corresponding decrease to any year 2002 increase.

service for the year 2001 officers' and directors' salaries to the 2.75 percent increase provided to union employees during that year. *Id*.

b. The Department Should Deny The Company's Attempt To Include And Annualize The Salaries Of Officers That Are Not Employed By The Company

Berkshire proposes to include in its pro forma cost of service the former Chief Executive Officer Scott Robinson and former Vice President Michael Marrone. Exh. BG-5, p. 11. Robinson and Marrone, however, are no longer employed by Berkshire. They were given their severance packages when Energy East acquired the Berkshire Energy Resources in September of the year 2000. Today, their positions have been filled by Mr. Robert Allessio as Chief Executive Officer and Ms. Karen Zink as Vice President whose are included in the Company's test year cost of service in this case. Exh. BG-1, p. 1 and Exh. BG-22, p. 1. Furthermore, the Company proposes to provide increases to the test year expense level of the Robinson and Marrone salaries to annualize their levels, and to further provide an 11.7 percent increase for the year 2001 and a 2.75 percent increase for the year 2002. Exh. BG-5, pp. 10-11 and Exh. BG-6, Schedule JJK-8. The Attorney General submits that all of the costs associated with Mr. Robinson and Mr. Marrone should be eliminated from the cost of service in this case. Customers should not be required to pay the salaries of phantom employees or their pay increases.

The Department sets rates based on the costs to provide gas utility service including a return on and of the investment in utility service.

> In calculating the costs incurred by a public utility to deliver its services to the public, COS/ROR ***regulation includes expenses such as wages and benefits to employees, depreciation on utility plant in service, and fuel, that the Department finds are reasonable or have otherwise been prudently incurred by the utility***. Next, the utility's level of allowable investment, or rate base is

> determine. A utility is also entitled to the opportunity to earn a reasonable rate of return on rate base, which represents a return that the utility's shareholders could earn in relation to other companies that are similarly situated and face similar levels of risk. (cites omitted). [emphasis added].

Incentive Regulation, D.P.U. 94-158, pp. 3-4 (1995). The Company's proposal in this case makes a sham of this underlying principle of ratesetting. Such "costs" are not incurred by the Company in the delivery of services to the public. The Department should reject the Company's proposal to include in its revenue requirement any costs associated with Mr. Robinson and Mr. Marrone, since these costs are not going to be, in fact, incurred in either the rate year or in the future.

There are also several other adjustment that must be made to remove the compensation associated with Robinson and Marrone. First, the test year amounts of base pay, bonuses, health and welfare benefits, 401K Plan, and FICA costs that should be removed can be calculated as follows:

TABLE OF FORMER EMPLOYEE EXPENSES

		Mr. Robinson Total Amount[22]	Mr. Robinson Expensed Amount[23]	Mr. Marrone Total Amount	Mr. Marrone Expensed Amount
Base Pay:	Amount	$166,327	$124,745	$109,443	$58,005
	Percent	100.00%	75.00%	100.00%	53.00%
Bonuses:	Amount	55,991	41,993	28,350	15,026
	Percent	100.00%	75.00%	100.00%	53.00%
Health & Welfare:	Amount	8,203	6,152	8,203	6,152
	Percent	100.00%	75.00%	100.00%	53.00%
401K	Amount	7,781	5,836	5,281	2,799
	Percent	100.00%	75.00%	100.00%	53.00%
EMPLOYEE TOTAL			$178,726	$80,177	
GRAND TOTAL					$258,903

See Exhibits AG-1-36 and DTE-1-6. Furthermore, the Department should reject the Company's proposal to annualize the test year wages associated with these employees. Since Mr. Robinson and Mr. Marrone left before the end of the test year in this case, the Company makes a $99,536 adjustment to test year costs to annualize there salaries as though they were employed for the entire year. Again, this proposal flies in the face of the Department's precedent of basing rates on the reasonable and prudent costs of providing service adjustment for known and measurable changes. *Incentive Regulation*, D.P.U. 94-158, pp. 3-4 (1995). Therefore, the Department should deny the Company's proposed adjustment to annualize the test year expenses

[22] See Exhibit AG-1-36 for total amounts under employee 2 for Mr. Robinson and employee 4 for Mr. Marrone. Tr. 13, pp. 1495-1496. .

[23] See Exhibit DTE-1-6 for the utility expense portions for Mr. Robinson and for Mr. Marrone.

associated with Mr. Robinson and Mr. Marrone, two officers that have long ago left the company, and reduce the cost of service accordingly.

2. The Department Should Reject The Company's Proposed Increase In Health Care Costs

The Company proposes to increase its test year cost of service by $182,245 for projected medical cost increases.[24] Exh. BG-6, Schedule 32. This represents a 19.8 percent increase over the test year medical expenses for the utility business.[25]

The Department bases a utility's rates on a cost of service adjusted for known and measurable changes. However, the Company's proposed adjustments to its test year medical expense is not known and measurable and overinflated. The basis for the Company's medical cost rate increases is the forecasts of its consultant for employee benefits Gallagher Benefits Services, Inc. ("Gallagher"). The Company could not show that Gallagher is either a forecaster of any stature or any accuracy that should be relied on by the Department. Tr. 14, pp. 1562-1564. To the contrary, the record shows that the Gallagher's forecasts or woefully overinflated. For the twelve months ended June 30, 2001, Gallagher forecast costs to increase 9.8 percent over

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[24] The total increase for medical expense of $182,245 is represented by the Calendar Year 2001 Cost Projections of 9.35 percent in the amount of $89,253 and the Rate Year 2002 Cost Projections of 8.9 percent in the amount of $92,992 as shown on Exhibit BG-6, Schedule JJK-32, lines 2 and 3. [$89,253 + $92,992 = $182,245].

[25] The test year medical expense attributable to utility operations of $920,106 can be determined from Exhibit BG-6, Schedule 32 as follows:

Test Year Medical Expense recorded on the Company's books:	$955,600
Adjustment to allocate medical benefits to Rentals	(6,694)
Adjustment to allocate medical benefits to Merchandising/Jobbing	(28,800)
Test Year Medical Expense Attributable to Utility Operations:	$920,106

the previous twelve months. Exh. BG-7, Supplemental Schedule H, p. 1 ("Total Fixed & Projected Costs – using actual annualized claims"). Medical costs actually increased only 4.73 percent during that period. Compare Exh. BG-7, Supplemental Schedule H ("Total Fixed & Projected Costs – using actual annualized claims") page 1, Effective for July 1, 2000 Actual Annual Cost of $1,306,551 and page 2 Actual Effective for July 1, 2001 Actual Annual Cost of $1,368,401. This is the known and measurable rate of change in medical expenses during that period and all that should be allowed by the Department in this case. If the Department were to use the actual 4.73 percent increase for 2001 and projecting that rate for the rate year, the adjustment to the Company's cost of service would be calculated as follows:

Test Year Medical Expense Attributable to Utility Operations: (as discussed *supra)*	$920,106	
Adjustment for year 2001 increase at 4.73 percent		$43,521
Year 2001 Medical Expense Attributable to Utility Operations:	963,627	
Adjustment for year 2002 increase at 4.73 percent		45,580
Total Increases In Expense		$89,101
Less:		
Adjustment for Rate Year Employee Co-Payments		(52,781)
Adjustment to allocate medical benefits to Rentals		(6,694)
Adjustment to allocate medical benefits to Merchandising/Jobbing		(28,800)
TOTAL ADJUSTMENT TO TEST YEAR BOOKED MEDICAL EXPENSE		$ 826

See Exh. BG-6, Schedule JJK-32.

The Department should deny the Company's proposed adjustment to medical expenses and increase its booked medical expense by $826 to reflect more reasonable increases in those costs.

3. The Department Should Allocate A Portion Of Its 401K Costs To Construction As Well As Non-Utility Businesses

The Company incurred $233,903 of costs associated with its 401 K Plan benefit for employees.[26] The Company failed to capitalize any of these costs during the test year in this case. *See* Exh. AG-1-40 (the dollar amount and percent capitalized of employee wages, salaries and benefits during the test year). Furthermore, the Company failed to allocate its 401 K Plan costs to non-utility operations. See Exh. BG-8, Appendix I, pp. 7-10 and Exh. BG-9, Non-Utility Schedules, Supplemental Schedule NU-F.

The Department recognizes that overhead costs, including employee benefits, should follow the costs to construction and non-utility operations. *Berkshire Gas Company*, D.P.U. 92-210, pp. 9, 13 and 18. Here, since the Company has failed to make either of those allocations, the Department should order the reduction of the pro forma cost of service to reflect such a future allocation. Specifically, the Department should use the allocations of wages and salaries to construction and non-utility operations to reduce the Company's test year 401 K Plan costs included in operations and maintenance expense.

The amount of wages and salaries capitalized during the test year was 11.5 percent. Exh. AG-1-40. The amount of wages and salaries allocated to non-utility operations during the test year was $1,366,477 or 17.78 percent of the total wages and salaries. [$1,366,477

[26] The total amount of 401 K costs of $233,903 can be found by totaling the 401 K costs in Exhibit AG-1-34, the chart of accounts, Account 926 – Employee Pensions and Benefits, Charge Codes 45043 and 45044, $230,903 and $3000, respectively.

/ $7,683,613].[27] Summing the two percentages means that 29.3 percent or $68,497 [$233,903 x 0.293] of the Company's 401 K Plan costs should be allocated to capital and non-utility operations. Therefore, the Department should reduce the Company's revenue requirement by $68,497 to reflect allocations of its 401K Plan costs to its construction and non-utility business.

4. The Department Should Deny The Recovery Of The Customer "Incentive" Payments

The Company proposes to include in the pro forma cost of service in this case $325,433 of payments that it made as "incentive payments" in an attempt to acquire new load on its distribution system. Exh. 5, pp. 26-27 and Exh. BG-7, Supplemental Schedule J. Mr. Kruszyna indicated that the program:

> [P]rovides direct benefits to ratepayers by adding load and revenues which, in turn, spreads the Company's fixed costs among a larger base. The program has an excellent return on the investment and provides the necessary growth opportunity to expand the base load and reduce the per-customer fixed cost to existing customers. *Id.*

The Company estimated the annual margins to be $180,389 as a benefit or $494 per new customer. ($180,389 / 365). Analysis of these claims actually shows that the proposed cost recovery actually increase customers rates substantially over any benefit received.

The Company's proposed recovery of the costs associated with the incentive plan include the incentive payments themselves ***as well as*** the additional marginal costs to bring those new customers, causing rates to ***increase*** as a result of the Company's incentive plan. The cost

[27] The percent of wages and salaries allocated to non-utility operations can be determined from the Company's Exh. BG-9, Non-Utility Schedules, Supplemental Schedule NU-F, line 32. There the total wages and salaries are $7,683,613. Id. The $1,366,477 amount allocated to non-utility operations can be determined by subtracting the Utility Operations amount of $5,469,915 and the Utility Capital amount of $847,221 from the total wages and salaries amount of $7,683,613. Id.

of the payments associated with the programs is $892 per customer. ($325,433 / 365). *Id.* The cost of adding new residential customers is $473. Exh. BG-20, Schedule JLH-4, p. 42. Furthermore, the income margins built into rates can only be 40 percent of the Annual Net Margins that the Company hopes to realize since they were most likely brought on during the summer of the test year which means that only 40 percent of the annual revenues and therefore, only 40 percent or $198 per customer of the annual margins would have been reflected in test year revenues. *See* July through December Sales as a percent of Total, Annual Return to the Department for the Year 2000. Therefore, the actual cost to the Company's customers is as follows:

Proposed Annual "Incentive" Payments	$892
Cost to Add New Customer	473
TOTAL ANNUAL REVENUE REQUIREMENT	$1,365
Estimated Annual Net Margins Received in Test Year	198
TOTAL NET ANNUAL REVENUE REQUIREMENT INCREASE	$1,167

This calculation shows that existing customers actually see their costs in the revenue requirement increase by $1,167 per customer as a result of the addition of the new customers including the "incentive" payment. Shareholders will enjoy the benefit of the additional margins in each year after the new rates go into effect, ***with no cost to them.*** Clearly, these incentive payments benefit shareholders more than customers, and therefore, these costs should be eliminated from the cost of service.

5. The Department Should Deny The Company Recovery Of Mr. Kelley's "Consultant" Fees

The Company has been paying its former Chairman Joseph Kelley $25,000 a year for what it describes as "consulting" fees that are being provided under an unwritten contract to provide "services." Exh. AG-5-16. The Company's revenue requirement witness Kruszyna indicated that those services potentially included consultation with Company employees and his goodwill within the community as well as his experience in the utility industry in assisting the executive team. Tr. 14, p. 1556. However, when the Attorney General requested documentation of any work that Mr. Kelley did for the Company during the test year, the witness came up empty-handed. Exh. AG-RR-41.

The determination of rates should be based on the costs of providing service to customers. *Incentive Regulation*, D.P.U. 94-158, pp. 3-4 (1995). The Company has provided no evidence that Mr. Kelley provided any such service. Exh. AG-RR-41. Even if one were to construe that Mr. Kelley provides some "goodwill" during the test year, (which is completely unsupported by the record), Department precedent requires the elimination of promotional advertising and goodwill costs, since cost recovery is allowed only when such expenses provide direct benefit to ratepayers. *Bay State Gas Company*, D.P.U. 92-111, pp. 201-203 (1983); *Boston Gas Company*, D.P.U. 88-67, Phase II, p. 112 (1988); *See also Boston Gas Company v. Department of Public Utilities*, 405 Mass 115 (1989). Since the Company could not show any direct benefit to customers for the costs incurred, the Department should deny recovery of Mr. Kelley's "consulting" fees , and reduce the Company's revenue requirements by $25,000.

6. The Department Should Deny The Company's Proposed Strike Continency Costs Amortization Period

The Company proposes to amortize $162,436 of Strike Contingency costs that it incurred during the test year over a three-year period, the average period it anticipates between union contract negotiations. Exh. BG-5, pp. 18-19 and Exh. BG-6, Schedule JJK-21. This adjustment results in the Company including $54,140 in its pro forma cost of service. *Id*. Berkshire proposal assumes that each and every time that the Company negotiates with its union it must anticipate and incur costs for a strike. However, the fact is that the last time that the Company actually incurred a strike from its union was more than 19 years ago in 1982. Tr. 14, p.1584 and Exh. DTE-RR-31.

The Department reject any adjustment for Strike Contingency costs based on the implausibility that it will be incurred. However, if the Department accepts the Company's request, it should reject the Company's proposed 3-year amortization period and instead use a 19-year amortization period that reflects the actual period between occurrences. This reduces the Company's proposed amortization from $54,140 to $8,549 ($162,436 / 19), reducing the Company's pro forma cost of service by $45,591 ($54,140 - $8,549).

7. The Company Has Not Met The Department's Requirements For An Inflation Adjustment

The Company proposes to increase its pro forma cost of service by $81, 705 for an inflation adjustment. Exh. BG-5, p. 28 and Exh. BG-6, Schedule JJK-7 and 36. The adjustment for inflation provides utilities an increase in their test-year residual operations and maintenance expenses by the projected change in the Gross National Product Implicit Price Deflator for the period from the mid-point of the test year to the mid-point of the rate year.

Fitchburg Gas & Electric Light Company, D.T.E. 98-51, pp. 100-101 (1998); *Boston Gas Company*, D.P.U. 96-50 (Phase I), p. 113 (1996); *Massachusetts Electric Company*, D.P.U. 95-40, p. 64 (1995); and *Cambridge Electric Light Company*, D.P.U. 92-250, p. 97 (1993).

When making the adjustment, the Department removes all expenses from the inflation adjustment that are either removed from the cost of service for distribution services or are not subject to inflation. *Id*. In order to allow an inflation adjustment, the Department has required utilities to describe all cost containment measure that they have implemented. *Id*. Here, the Company has neither met the minimum requirement to show its efforts at cost containment. See Exh. BG-5, p. 28. Nor has the Company even made such an attempt in this case. There is no evidentiary basis upon which the Department can make a determination in support of the proposed adjustment. Therefore, the Department should deny the Company's request for an inflation adjustment and reduce the cost of service by $81,705. *Fitchburg Gas & Electric Light Company*, D.T.E. 98-51, pp. 100-101 (1998); *Boston Gas Company*, D.P.U. 96-50 (Phase I), p. 113 (1996); *Massachusetts Electric Company*, D.P.U. 95-40, p. 64 (1995); and *Cambridge Electric Light Company*, D.P.U. 92-250, p. 97 (1993).

8. The Company Should Reimburse Customers For The Gifting Of Assets To Officers

Berkshire simply gave away two of its cars to the officers who retired during the test year. The Company received no compensation for the automobile given to its former CEO Mr. Robinson and received only $10,269 for the automobile it gave to its former VP Mr. Marrone. Therefore, the Department should order the Company to reduce the cost service by the market value of those vehicles given away. Mr. Robinson's car was worth $14,890. Exh. AG1-20, p. 3. Mr. Marrone's was worth $13,519, for which the Company only received $10,269 in compensation, resulting in a net loss of $3,250. *Id*. Therefore, the Department should reduce the cost of service by $18,140 to recognize the gift of Company assets to former employees.

9. The Company Failed To Allocate Computer Lease Costs To Its Non-Utility Businesses

The Company failed to allocate any of the $939,065 of computer lease costs to its non-utility businesses. Exh. BG-9, Supplemented Schedule NU-B, p. 5. Although the Company claims that the other businesses rely on their own computers, this is not supported by the record. *Id*., p. 2. First, the evidence demonstrates that the merchandising and jobbing businesses do not have any computers at all and rely totally on the utility's computer systems. *Id*. Second, the computer system infrastructure for the utility as well as the non-utility businesses is all supported by the personnel and systems at the gas distribution company. *Id*., pp. 3-5. The Company's claim that none of the system is used by non-utility businesses is contradicted by the allocation of the distribution company's personnel and assets. *Id*., pp. 3-5. Clearly, the time of the systems personnel at the distribution company cannot be allocated to the non-utility businesses without allocating all of the other overhead costs required to support them, including the costs of the computer leases. Therefore, at a minimum, the Department should allocate 2.82 percent of the costs of the Company's computer leases to its non-utility businesses and reduce the cost of service accordingly.[28]

[28] The allocation of the computer lease cost should follow the allocations of the other non-lease computer costs to the non-utility businesses, including (1) the employee salary allocation and (2) the other expense allocations:

	Salary Allocations	Other Expenses	Total
Merchandising	$860	$28	$888
Jobbing	5,720	3,027	8,747

10. Rate Case Expense

a. Legal and Consulting Services

(1) Standard of Review

Companies are under an affirmative duty to contain rate case expense. *Fitchburg Gas And Electric Light Company*, D.T.E. 98-51, p. 57 (1998). In D.P.U. 96-50, the Department put Massachusetts utilities on notice that outside legal and consulting services must be subject to a competitive bidding process or an adequate justification must be provided for the failure to issue a request for proposal ("RFP"). *Boston Gas Company*, D.P.U. 96-50, p. 79 (1996). The existence of a utility's potential self-dealing with outside counsel heightens the obligation of a company to issue a RFP and impose cost containment controls. *Cambridge / Commonwealth Electric Company*, D.P.U. 92-250, pp. 121-131 (1992) (member of board of trustees for company also partner at law firm working for the company). Invoices for services provided to the utility should contain sufficient detail to describe the nature of work. *Fitchburg Gas And Electric Light Company*, D.T.E. 98-51, p. 61. Vague or general descriptions are simply

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Rentals	6,831	3,888	10,719
Berkshire Propane	3,254	4,221	7,475
Berkshire Service Solutions	522	0	522
Total Allocated	$17,187	$11,164	$28,351
Total Costs	$380,575	$624,554	$1,005,129
Percent of Total			2.82%

Exh. BG-7, Supplemental Schedule NU-B, p. 5.

insufficient. *Id*. Failure of a Company to adhere to any of these requirements may result in disallowance of the requested rate case expense. *Id*. pp. 56-61. In the Company's last rate, the Department specifically put Berkshire on notice that the Company must be prepared to fully justify rate case expense in the future. *Berkshire Gas Company*, D.P.U. 92-210, p. 84 (1993).

(2) Legal Services

Berkshire did not issue an RFP to solicit competitive bids for legal services in connection with the rate case and did not provide a credible explanation for this failure during the hearings. Tr. 14, pp. 1521-1541. The Company took no formal steps to determine whether another law firm would charge either a lower hourly rate or could prepare and defend the Petition in fewer billable hours. Tr. 14, p. 1528-1529. Although the Company believed that the $225 / hour charged for the rate case compared favorably to the rates charged by other firms, Tr. 14, p. 1527-1528, this belief ignores the fact that an experienced Boston firm specializing in utility work recently charged $150-165 / hour in connection with a gas rate case, 33% less then the rate paid by Berkshire. *Fitchburg Gas And Electric Light Company*, D.T.E. 98-51, p. 60. The Company's witness testified that the maximum rate charge by its law firm was between $225-250 / hour, but the Company had no explanation for why charges appeared on Berkshire's invoices for up to $350 / hour in connection with test year expenses. Tr. 14, p. 1538; Exh. DTE 4-11. The legal invoices from the firm handling the rate case and working extensively for the Company during the test year contain absolutely no description of the nature of the legal work purportedly performed for Berkshire on a daily basis.[29] Exh. DTE 4-11, Exh. AG 5-28, Exh.

[29] Certain pages from each month's invoices were "missing" and never provided by the Company during these proceedings. Tr. 14, p. 1535, AG-RR-38, AG-RR-38 (supplemental response) (stipulation *in lieu* of motion to compel production of documents). No explanation has been provided for what information was contained on these pages.

AG 3-9, AG RR-38, AG RR-38 (supplemental response). Instead, the total invoices are broken down by general project on a monthly basis. Exh. DTE 4-11. Looking at these summary invoices it would be impossible to understand what legal services were performed for the Company. No prudent corporation would ever agree to pay hundreds of thousands of dollars in legal fees from an outside firm without a simple description of the tasks.[30] This practice of submitting "summary bills" contrasts sharply with the reasonably detailed, daily invoices provided by other law firms working for the Company. Tr. 14, pp. 1533-1534, Exh. DTE 4-11 (comparing legal invoices from Martin & Olivera, Edward & Angell and Glenn Dawson, Esq. with invoices from Rich, May, Bilodeau & Flaherty), AG-RR-39 (comparing legal invoices from Brown Rudnick Freed & Gesmer with legal invoices from Rich, May, Bilodeau & Flaherty). Finally, for at least part of 2000, a partner of the firm retained during the test year and for the rate case also held the position of chairman of the board of trustees for Berkshire's parent company, BER. Tr. 14, pp. 1531-1532; Exh. AG 4-5, August 22, 2000 minutes from BER board of trustees, Tr. 16, p. 1871. Energy East acquired BER during 2000. Exh. AG 4-5.

In summary, the Company lacked objective criterion on which to judge either the hourly rate charged by the outside firm or the total time necessary to complete the desired legal services. The form of the legal invoices accepted by the Company utterly lack detail of a type that would allow the Company to review the cost efficiency of the firm objectively or even to know what legal tasks were being performed. The presence of the potential for self-dealing added to the other murky circumstances surrounding this issue makes the need for an RFP critical. Berkshire did not solicit competitive bids, adequately explain why it did not issue an

[30] Considering the lack of adequate detail in the invoices, it is difficult to imagine how the Company would protect its interests during a malpractice suit or a suit over legal fees since the Company would have little written proof as to what the law firm did for the Company.

RFP or describe a system of objective management controls relative to monitoring legal expenses. As a result, the Department should reject the Company's requested recovery of rate case expense for legal services.

(3) Consultant Services

Rate case expense exceeding the initial estimates provided by the consultants needs to be adequately justified, including an explanation of the cost containment efforts instituted by the Company to help reduce the costs associated with a particular consultant. *Fitchburg Gas And Electric Light Company*, D.T.E. 98-51, p. 59. The original rate case estimate provided by MAC for rate design had been met or exceeded before the start of hearings in this matter. Tr. 14, pp. 1544-1545, 1551-1552, Exh. BG-6, Schedule JJK-38. As this estimate included separate line items for initial case preparation, discovery and hearing time, the estimate accounted for all of the major cost factors of a rate case. *Id*. Berkshire did not offer a convincing explanation for why the MAC consulting fees greatly increased or what efforts the Company undertook to control these costs. Given the overlapping areas of testimony for Berkshire's numerous witnesses and the hiring of two experts for testimony from MAC when the Company historically relied on only one for previous rate cases, AG-RR-55, the Company has virtually assured that rate case costs would spiral to unreasonable levels. As a result, the Department should reject the inclusion of rate case expense beyond the original estimates.

11. The Department Should Adjust The Amount Of Excess Deferred Income Taxes The Company Is Flowing Back To Customers

The Company recovers from customers revenues to compensate for its income tax liability. See. Exh. BG-6, Schedule JJK-5. As a result of changes in income tax rates, the amount of taxes the Company has booked to deferred income taxes is greater than its current liability.[31] As a result, the Company is flowing back those excess deferred income taxes to customers over the average remaining life of the assets that gave rise to those deferred tax liabilities. *Berkshire Gas Company*, D.P.U. 90-121, pp 139-140. (1990).

The Company calculated an amount of remaining excess deferred income taxes to be flowed back as required by the Department in D.P.U. 90-121, p. 140. It determined that as of December 31, 2001, $252,109 will remain, resulting in a 6.44 year remaining amortization term based on the $39,158 annual amount ordered in D.P.U. 90-121. Exh. BG-5, p. 24 and Exh. BG-6, Schedule JJK-31. Mr. Kruszyna based all of this calculations on the assumption that the taxes were accrued in the past at the 46 percent federal income tax rate. *Id*. However, as he agreed during cross-examination, the actual tax rate varied from 52.8 percent to 46 before the TRA of 1986. Tr. 4, pp. 521-523. These actual higher tax rates create a larger balance of excess deferred income taxes to be returned to customers of $292,095. This extends the number of years that the Company would be amortizing the balance beyond the 6.44 years the Company originally calculated, assuming the original $39,158 annual amount. Exh. DTE-RR-11. Therefore, the Department should order the Company to amortize it balance of excess deferred income taxes to reflect the actual historical income tax rate, rather than the Company's assumed 46 percent rate.

[31] Deferred income taxes are accrued when a utility has a current deduction or credit for tax purposes, but not for book purposes. The Tax Reform Act of 1986 ("TRA") reduced the corporate tax rate from 46 percent to 34 percent as of July 1, 1987. By reversing its reserve for deferred income taxes at the new lower rate, whereas it had accrued the reserve at the former higher rate, the utility is left with excess deferred income taxes. *Berkshire Gas Company*, D.P.U. 90-121, pp 139-140. (1990).

12. Unrecovered Environmental Costs are Unrecoverable

The Company has included in the test year cost of service approximately $104,000 of "unrecovered" environmental (remediation) costs. Exh. AG-2-4, p. 12-1, line 9. According to Mr. Normand's workpapers, this cost was booked to Account 814, Other Gas Supply Expenses-Environmental. Exh. BG-18, p. 50. Mr. Normand was informed that of the total $249,102 booked to Account 814, the $104,000 was an unrecovered or unrecoverable amount (see handwritten note on workpaper that segregates the total cost into the two amounts–the $104,000 labeled "Unrec."). This unrecovered cost was included in the Company's cost of service as a test year expense allocated to the gas supply function to be recovered through the Company's proposed CGA. *Id.* and Exh. AG-2-3, p. 12-1, line 9 (CGA Cost of Service Study).

Prior to the unbundling of rates, remediation costs were recovered through companies' CGACs. As part of rate unbundling these costs were moved to an automatic adjustment provision, the Local Distribution Adjustment Clause ("LDAC")[32]. The LDAC allowable costs are recovered from all customers, not just gas sales customers. As part of the cost allocation process in developing the Company's unbundled rates, Mr. Normand removed all test year LDAC costs and revenues from the revenue requirement calculations. Exh. AG-8-1. When questioned about the inclusion of an amount that should have been removed with all other LDAC costs and revenues and appears to be labeled "unrecoverable", Ms. Zink responded:

[32] Environmental response costs were the subject of a settlement agreement that specified what categories of costs were recoverable and the method of recovery. *Generic investigation of the facts surrounding and the ratemaking treatment of the costs of investigating and remediating hazardous wastes associated with the manufacture of gas during the period 1822-1978*, D.P.U. 89-161 (1990) (approving the settlement regarding cost recovery) and D.P.U. 90-151/152/182/198 (1990)(establishing the format for recovery of remediation costs).

> The term "unrecoverable" that he's handwritten meant the portion that's not recoverable through the LDAC. It was determined in the early '90s, when that settlement came out, that LDCs would be able to recover a portion of environmental costs as a deferred-tax benefit. The company is unable to do that. So up until the point that we file this case, there's been an amount that we have not recovered on a year-to-year basis. We can only recover one-seventh of the expenses less the deferred-tax benefit that was assumed to be a benefit that we haven't actually incurred. And that net amount is all that we can recover through the LDAC.

Tr. 12, p. 1334. In response to a record request, the Company provided several “tax service” documents, but not the original documentation from its tax advisor that caused the Company to believe certain remediation costs were not “currently” deductible. AG-RR-30. The Company claims that the current deductibility is related to the Company having purchased a certain already polluted site; the Company was therefore not the party responsible for the pollution. *Id.* Whatever the basis is for the claimed loss of tax benefits, the Company is not entitled to recover remediation related costs in base rates or through the CGA (applies to gas sales customers only) The Department has ruled that remediation costs may not be recovered through base rates unless a company specifically petitioned for such treatment *in lieu* of recovery as specified in the settlement agreement and then only under certain conditions. D.P.U. 89-161, pp. 35-37. and D.P.U. 90-151/152/182/198, p. 57.

The Company has not petitioned for the recovery of unrecovered environmental costs through base rates or proposed any change to the current recovery method. The Company has not put forth an affirmative case in support of such changes-- it has just simply folded these costs into its revenue requirement. The Attorney General urges the Department to disallow recovery of the unrecovered environmental costs and put the Company on notice that it must provide, at a minimum, explicit testimony and supporting materials whenever seeking to change the traditional treatment afforded a specific type of cost.

13. Supplemental Executive Retirement Plan

The Company proposes to include in its pro forma cost of service the accelerated costs the severance packages associated with the early retirement of its executive officers. Exh. BG-6, Schedule 28. The Company's CEO and VP both left the Company as a result of the acquisition by Energy East. This forced the Company to make accelerated payments to the trust funds for these officers under the Supplemental Executive Retirement Plan ("SERP") agreements the Company had with those employees. Exh. BG-7, Supplemental Schedule G. But for the acquisition, the Company would not have been required to make these accelerated payments. *Id*.

The costs of the acquisition of the Company by Energy East are not a cost of providing gas distribution service. The Company's has not proven that the acquisition will provide any savings to customers. Therefore, the Department should deny the Company's proposal to include the accelerated payments to the SERP trusts that are caused by the golden parachutes provided to its executives and reduce the cost of service by $285,153. Exh. BG-6, Schedule JJK-28. Even under the Company's own logic of the "stand alone" calculations, this cost should not have been included in the cost of service.

V. RATE STRUCTURE

A. THE COMPANY'S PROPOSED USE OF AN MBA ALLOCATOR IS UNNECESSARILY COMPLEX AND MAY THWART COMPETITION BY DESIGN

1. BACKGROUND

Currently Berkshire recovers its seasonally allocated gas costs through an average Cost of Gas Adjustment ("CGA") rate charged all its customers. The Company is proposing a significant change to its CGA calculations. Its proposal involves calculating CGAs for two distinct classes, High Load Factor and Low Load Factor. The High Load Factor class is made up of customers who are served under the Company's R-1, R-2, G/T-51, G/T-52, and G/T-53 tariffs. The Low Load Factor class is made up of customers served under the R-3, R-4, G/T-41, G/T-42 and G/T-43 tariffs. Essentially, the Load Factor designation relates to customers' average use relative to peak use and may be determined by dividing average monthly use for 12 months by the average monthly use for the peak months. Generally, the higher the load factor the easier it is to serve the load, primarily due to less fluctuation in demand.

Historically, companies have recovered gas cost changes through a uniform automatic adjustment clause that recovered costs through an average volumetric charge. CGA allowable costs are allocated using a Proportional Responsibility allocator[33] that formulaically allocates more costs to the peak season through the calculation of a base and supplemental (peak season) gas cost components. Exh. AG 2-5. With the advent of open access and the unbundling of rates into the distribution and gas cost components, local distribution companies have sought to provide customers with appropriate prices to compare to competitive offerings, while at the same time reflecting the actual costs to serve. Class differentiated CGA factors were first adopted as part of a settlement in the 1995 Bay State Gas Company unbundling case, D.P.U. 95-104. The class specific allocations were based on a version of the MBA allocator proposed by the Company's witness, Mr. Harrison. The Attorney General, although a signatory to the settlement, specifically stated that he "...does not acknowledge, accept or endorse the use of the

[33] Proportional Responsibility allocators are used to allocate costs to customers (individual customers, classes, load factor or other groupings) based on the weighting of volumes delivered or consumed in specific time periods (hours, days, months or peak and off peak). The volumes used may be actual, normalized or design depending on the type of costs to be allocated. Exh. DTE-3-36, *Berkshire Gas Company*, D.P.U. 92-210, p. 210 (1992), and *Commonwealth Gas Company,* D.P.U. 91-60 (1991), pp. 21-22.

Market Based Allocation ('MBA") method of allocating gas costs between rate classes..." *Bay State Gas Company*, D.P.U. 95-104, p. 5 (1995). In 1996, both Fall River Gas Company and Essex Gas Company filed rate cases that proposed the unbundled rates and introduced class specific CGAs. Each company relied on an MBA allocator to create the class factors[34]. *Fall River Gas Company*, D.P.U. 96-60 (1996) and *Essex Gas Company*, D.P.U. 96-70 (1996). Mr. Chernick presented testimony on behalf of the Attorney General in both cases. His testimony addressed the concerns that the MBA is too subjective and complex a methodology that produces results that are biased in favor of the high load factor customers. Both Fall River and Essex cases were settled, and as part of the settlement agreements Fall River kept the single, seasonal average CGA factor and Essex implemented class specific seasonal CGA factors. Although the Essex settlement provided for class specific CGA rates as proposed by the Company, the Attorney General did not embrace, or even acknowledge, the use of an MBA allocator and required that the residential CGA rates not exceed the average CGA rate by a fixed percentage. *Id.* In 1998, Fitchburg Gas and Electric Light Company filed a gas rate case that included the unbundling of its tariffs. The case was docketed as D.T.E. 98-51. Mr. Harrison sponsored the Company's load factor based CGA proposal that relied on an MBA allocator. In the Fitchburg case, the Attorney General argued that the introduction of load factor CGAs, as proposed, was an unnecessary complexity at a time when retail gas markets were opening to competition. Attorney General's Initial Brief, pp. 46-48. The Department found in the Fitchburg case that load factor based CGAs, when compared to an average CGA factor, reflected costs more accurately and were more likely to lead to more effective competition by reducing "cherry

[34] Mr. Harrison was the sponsoring witness in the Fall River case; the Essex proposal was sponsored by its own witness.

picking." *Fitchburg Gas and Electric Light Company*, D.T.E. 98-51, p. 153. It is important to highlight that currently only three of the ten Massachusetts' natural gas companies have class or load factor CGAs and the Department has never explicitly accepted or approved the use of the MBA allocator in approving class or load differentiated rates–only in Fitchburg did the Department state a preference for load based CGAs in general--not for a specific allocation methodology.

2. THE COMPANY'S PROPOSAL

Berkshire has presented Mr. Harrison as the sponsor for its class/load specific CGA proposal. Mr. Harrison relies on the use of a "simplified" MBA allocator to allocate upstream[35] gas costs to each of the Company's customer classes. The resulting class gas costs are summed into two categories–high load factor and low load factor, as described above. The theoretical guise under which the MBA is developed is one which attempts to replicate competitive suppliers' (the market), costs to serve or provide gas service to these distinct and often diverse customer groups. The development of the MBA allocator begins with segregating the utility's load into two portions (base use and remaining load). It separately assigns costs to each customer class/group based on its allocation of base use and remaining load. Exh. BG-19, p. 10. Mr. Harrison's MBA allocation factors are combined with the allocated production, storage, gas acquisition and related overhead costs from Mr. Normand's cost study to produce the CGA factors calculated by Ms. Boucher. Ms. Boucher's factors are then applied to the total allowable CGA costs to produce the load factor CGA rates. Tr. 6, pp. 748-750, Exh. BG-26,

[35] Upstream gas supplies are supplies from sources that are delivered by connecting interstate gas pipelines. Berkshire's upstream resources include pipeline delivered supplies from U.S. production areas, Canada and stored gas. Downstream supplies are generally those sources of gas that are within the distribution company's service territory and do not require delivery by an interstate pipeline. Berkshire's downstream resources include the Whately LNG and propane.

Sch. JMB-6 and Exh. AG-6.

The Attorney General presented rebuttal testimony of Mr. Paul Chernick of Resource Insight, Inc. to refute the Company's claims regarding the propriety and simplicity of the proposed MBA allocators. Given Mr. Chernick's consistent and undisputed testimony regarding the subjective judgements required to compute MBA allocators; as well as the unnecessary complexity the use of even simplified MBA allocators introduces into the tenuous CGA review process, as discussed below, the Attorney General continues to oppose the adoption of the MBA allocator. The Attorney General urges the Department, at this time during the transition to competitive retail market, to deny the Company's proposal for load factor based CGA rates and open an investigation into the operation of all gas utility CGAs to determine the most appropriate way to price natural gas as a default service in a competitive market.

3. The Propriety of Using MBA Allocators

"Competition" is the Company's main rationale for its MBA proposal. According to Mr. Harrison, continued reliance on the Proportional Responsibility allocation method and seasonal CGA will provide an unfair advantage to marketers who compete for high load factor loads; thus leading to migration based on "cherry picking". Exh. BG-19, p. 7. As pointed out by Mr. Chernick, there is no relationship between the Company's proposed allocators and competitive pricing. It is not clear that there is a problem[36], not clear that MBA would match market conditions any better than the PR (see discussion below of Mr. Harrison's hypothetical), and not clear that the Company's proposed "load-factor CGAC" would solve any problem. However, the Company's MBA might introduce serious inequities, especially considering the

[36] According to data supplied showing migration over the past several years, it appears that the high prices of recent several years has spurred migration even under the average, seasonal CGA.

lack of opportunity for review.

Mr. Chernick points out:

1. The Company's MBA is not based on market prices.

> ...the Company has proposed a mix-and-match approach, which may or may not depend on historic prices, may or may not raise rates to low-LF customers and may or may not be much different from the PR allocator, but has nothing directly to do with market pricing and does not accurately reflect utility cost incurrence. Exh. AG-7, p.3.

> Furthermore, it fails to reflect market prices by the simple fact that it includes only utility costs, not competitive suppliers costs. Utility costs can be higher or lower than the market. *Id.* at 15.

2. Migration is not necessarily undesirable.

> The objective should not be to retain the high-LF customers; it should be to retain them at a margin or lose them. The Company should endeavor to price *all* customers correctly, not to subsidize one class of customers at the expense of another and to the detriment of the developing competitive market. *Id.* at 14.

> In terms of regulatory goal, if the Department wants to encourage a competitive market for gas supply and wants to gradually get the LDCs out of the gas-supply business and have them just be distribution companies, then migration is the path to that end. That's a determination that the Commission has to make. If the Commission didn't want marketers to be competing with the utilities, I don't know why it would have put retail access in place in the first place. But if it wants competition, then it has to accept migration.

Tr. 17, pp. 1981-1982.

3. The Company exaggerates what it would be up against in "the market."

> Contrary to the assumption underlying the Company's MBA approach, the marketer does not have the ability to procure an exact quantity of the lowest cost resource at all times for the base use portion of a customer's load. In order to meet the prices developed by the Company's MBA method for the Company's definition of "base use," a marketer would have to:

> > acquire sufficient resources to meet potential changes in base use and then

absorb the costs of any resources in excess of actual use;

price sales for base use as though it had a 100% load factor, and provide additional capacity required by this load without charge;

share margins on interruptible sales with the "base use" sales, even though those sales would not pay for enough capacity to support their own use, let alone interruptible sales;

charge no additional margin or profit on "base-load" sales to cover any of the above costs, or to compensate for the risk that the "base-load" sales will decline due to customer operating levels and changes in gas supplier.

It is unlikely that marketer's would choose to assume these costs and risks and absorb the resulting losses for any length of time. *Id.* at 17.

4. The Company has not demonstrated that the MBA would match market conditions any better than the PR.

The Company's attempt to prove its claim is based on an irrelevant hypothetical that does not even compare "market price" with any of the allocation methods that are actually at issue in this case: his MBA approach, the PR approach, or the pricing method the Company has actually been using. In addition, the hypothetical is based on an unrealistic view of the gas market and an over-simplified view of the costs to the utility and to the marketer of supplying gas. When Mr. Chernick expanded the Company's hypothetical to compare a PR approach with the Company's MBA, as he best understood it, under either the MBA or the PR allocator the marketer's price would not be competitive and the customers would stay with the Company. Exh. AG-7, pp.18-19.

5. Company's proposal would not eliminate the problem of cherry-picking, if it is a problem:

...under the company's proposal each customer within not just a rate class but a whole group of high-load-factor rate classes, for example, would be paying the same CGA, and therefore. . . the ones that happen to be cheapest within that group would still be subject to cherry-picking. Tr. 17, p. 1918.

6. Acceptance of the Company's proposal would permit the Company to assign and price resources arbitrarily so as to undersell the marketers due to the complexities highlighted below.

d. Complexities and Inaccuracies Introduced by the MBA

The Attorney General's witness Mr. Paul Chernick, is familiar with the theory and computations involved in the development of MBA allocators, having reviewed the computations and applications in both the 1996 Fall River and Essex cases. Mr. Chernick, after significant effort to unwind the complex calculations and the less than transparent application of Mr. Harrison's MBA allocators, concluded that the proposal is not based on a realistic model of the design, planning and operation of a gas system, would tend to underprice base load use and allocate excessive costs to low-load-factor loads, and relies on a methodology that is too complex, given the numerous judgements that are incorporated in the development of the allocators, to be adequately reviewed in either the compliance filing or during a traditional CGA filing and approval process. Exh. AG-7, p. 4, Tr. 17, pp. 1901-1902.

1. The MBA allocators are based on unrealistic and biased assumptions:

> The company arbitrarily, and I think illogically, assumes that more expensive gas is necessary to fill storage than the gas that's used by base load customers on the same day. It just assumes that. No basis, no rationale for it at all; just customers' use in May, June, August, that's somehow cheaper than the gas that's being put into storage on the same hot days. Tr. 17, pp. 1947-1948.

> The Company's MBA understates the capacity requirements of base use by treating the average daily demand in a month as though it were the same every day. Exh. AG-7, p. 4 and Tr. 17, pp. 1946-1947. Mr. Harrison acknowledges that base use uses more capacity to meet its daily load fluctuations than it pays for under the Company's MBA approach. Tr. 17, pp. 1733-1744. Furthermore, this inequity is exacerbated-- under Mr. Harrison's cost assignments, the base use receives cheaper gas and the remaining load receives more expensive gas for injection to storage even though the remaining load is paying for the capacity.

> The MBA understates the base-load cost by assigning to the remaining load all costs resulting from real world complications–excess capacity, planning risks and errors, the value of diversity (for reliability and to take advantage of price fluctuations), and the need for back-up supplies. Exh. AG-7, pp. 15-17, 20.

> Mr. Harrison allocates remaining capacity costs to rate classes based on the single design peak day (net of base use), clearly in appropriate for pipeline and storage capacity. The utility acquires pipeline and storage resources with high capacity

costs an low commodity costs to meet load that must be met many days of most years. Exh. AG-7, pp. 21-22 and Tr. 17, 1948.

The Company allocates a share of interruptible margins to "base use" consumption, even though base use is not allocated the resources that could serve interruptible sales. Exh. AG-7, p. 23. Mr. Harrison agrees that interruptible sales margins should be allocated on the basis of the remaining demand. Tr. 15, p. 1728.

2. The MBA Methodology is Complex and Involves Many Subjective Judgements:

Mr. Chernick testified that the MBA allocations "... can have a significant impact on rates and involve a complex calculation that requires many subjective judgements about the categorization of send out and gas supplies and about the assignments of supplies and costs. ....(A)approval by the Department of this proposal would give the Company too much discretion in gas pricing." Exh. AG-7, p. 4.

Since Mr. Chernick prepared his testimony he learned that the Company was proposing to come in with a completely new CGA calculation , based on new methodologies, based on new projected data, none of which the Department or the parties have seen before, in a compliance filing in this proceeding–essentially asking the Commission to remove all control over the Company's allocation of approximately 50% of the Company's costs. Tr. 17, pp. 1901-1902.

e. Recommendation

For all of the reasons stated above, the Attorney General recommends that the Department refrain from accepting the load factor based CGAs as proposed by the Company. The Attorney General urges the Department to open an a generic proceeding to determine the most appropriate way for all local distribution companies to set default service gas prices, during the transition to a fully competitive gas market in Massachusetts. Should the Department find that it must adopt load factor CGAs for Berkshire, the Attorney General believes that the Department should reserve the implementation of a load factor CGA until the Company, the Department and other interested parties have had an opportunity to explore alternatives or modifications to the Company's proposed load factor calculations that are to be revealed in its compliance filing. This further investigation could be accomplished by opening a second phase of this docket.

B. PCM Proposal Is Too Flexible and Contravenes Department Precedent

The Company filed its proposed PBR compliance plan as a set of Terms and Conditions, Exh. BG-24, Exhibit KLZ-1 sponsored by Ms. Zink. As Ms. Zink explains, after base rates established in this case are frozen for 31 months[37] they will be adjusted annually[38] according to a set formula. The formula adjusts the previous year's inflation rate, as measured by the Gross Domestic Product Price Index (chain weighted) ("GDPPI"), by an "enhanced" productivity off-set of 1%. The resulting price cap adjustment factor[39] used to establish the price cap for the following year's rates effective on September 1 beginning in 2004[40]. The Company

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[37] Throughout the ten year proposed Price Cap Plan base rates may be adjusted for exogenous costs. Exh. BG-21, pp. 13-14. The Company's intent to include adjustments for exogenous costs during the rate freeze period, but not adjustments related to Service Quality performance (Tr. 3, pp. 396-397) is inequitable and contrary to the spirit of the Department's rulings in the Service Quality dockets:

> To facilitate a speedy transition to these guidelines, however, the Department directs each electric and local gas distribution company to begin collecting, as of the date of this Order, all the data necessary to implement a SQ plan based on these guidelines.

Service Quality Standards, D.T.E. 99-84 (2001). The Department should not permit the Company's proposal to delay the implementation of its Service Quality Plan beyond 2002, the implementation date for other Massachusetts utilities.

[38] The PCM Terms and Conditions may be read to allow the Company to initially incorporate the affects of inflation during the 31 month rate freeze period. This should not be allowed–the rate freeze truly would be a sham, simply a deferral and accumulation of rate increases.

[39] The Company's proposal converts exogenous and service quality adjustments to percentage factors and incorporates these in its price cap adjustment rate. Exh. BG-23, Exhibit KLZ-1, p. 6, Exh. AG-9-2, and Tr. 3, pp. 302-304.

[40] It should be noted that the Terms and Conditions do not specify whether the Company will be using calendar year revenues to establish the revenue base to which the annual price cap applies. The Attorney General urges the Department to require the PCM implemented using calendar year data in order to expedite the review process by having available publically filed

proposes to apply the price cap adjustment factor to the prior year prices/rates and design each class's rates for the next year so that rates will increase or decrease at the price cap rate. The Company further proposes that it have the discretion to allocate each class's increase or decrease in such a way that individual rate elements would not change by more than the rate of inflation. Should there be an adjustment for exogenous costs, the rate components would change at rate no more than the rate provided in the price-cap formula. *Id.*, pp. 2-4.

During cross examination and in responses to data and record requests Ms. Zink and Dr. Gordon fleshed out the rate design provisions of the PCM. From all the information provided it is unclear exactly what the Company's PCM pricing provisions are. According to the language of the PCM Terms and Conditions, "Berkshire shall be authorized to allocate the particular price cap increase or decrease within a class at its discretion so long as no rate component increases by more than the rate of inflation (Boston Gas, D.P.U. 96-50, p. 332)...the limitation just described ensures that, absent Exogenous Cost recovery, no individual rate component shall increase by greater than the rate of inflation during the term of the plan." Exh. BG-24, Exhibit KLZ-1, p. 4. It is clear from this language that the Company intended to portray their proposal as being in complete compliance with the rate design provisions of the Boston Gas Company Plan, although the Company's proposal does not include the provision that no rate class's increase may exceed the price cap rate, as was the Department's requirement in the Boston Gas PBR plan. *Boston Gas Company*, D.P.U. 96-50, pp. 326-334 (Department accepts Company's withdrawal of proposed **interclass** pricing flexibility and rules on **intraclass** pricing flexibility).

During cross examination, Ms. Zink states that "...no one class could have their

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data for comparison purposes (ie., Annual Returns to the Department and SEC filings).

rates increase by more than the rate of inflation. The only classes that would be increased up to the rate of inflation would be those classes that are not at or near their equalized rates of return, as calculated in our cost-of-service study..." Tr. 3, p. 305. Ms. Zink goes on to describe how the Company would look at customers that are not at their equalized rates of return and evaluate increasing their rates by up to the rate of inflation; while at the same time possibly decreasing rates[41] to customers that "...would really impact all customer classes if they were to leave our system." Id. at pp. 305-306. Dr. Gordon holds a somewhat different view of how pricing flexibility should work. Dr. Gordon believes that pricing flexibility would allow a company to charge "...lower-than-normal rates to large customers who are possibly in danger of leaving the system." Tr. 8, p. 924. He continues–"By operation of the price cap plan, the company would not be free to move any costs away from that customer to other customers. The price cap plan itself would prevent that." *Id.* Dr. Gordon supports the proposed pricing flexibility because "...the risk of making an error on the discount does lie with the shareholders, not with the other customers...the virtue of the price cap type plan is that if the management makes a mistake and gives a discount to somebody who didn't really need a discount, its their bottom line that eats it." *Id.*

The Department has long held that a discount given to one customer is not recoverable from another.[42] *Investigation by the Department on its own Motion to Revise the*

[41] Ms. Zink states that the marginal cost study would be the guidepost for "discounting" rates, but as Dr. Gordon states, the marginal costs are generally used only for "temporary" load. Tr.3, pp.335-337 and Tr. 8, pp. 926-927. Generally, it is inappropriate to discount existing customers to rates less than tariff rates for the obvious reasons that run the gamut from the potential introduction of intra and/or interclass subsidies to the potential for discriminatory pricing.

[42] Department has denied recovery of discounts from tariff rates. *Massachusetts Electric Company*, D.P.U. 95-40 (1995); *Boston Edison Company*, Manufacturing Retention Rate,

Standard of Review for Electric Contracts Filed Pursuant to G.L. c. 164, § 94, D.P.U./D.T.E. 96-39-A (1998). The implementation of a price cap plan should not be cause for the Department to change its policy. The Company's proposal appears to be at odds with both Dr. Gordon's position and Department precedent–there is no provision that would prohibit the Company from reducing rates charged to one class or to individual customers and off-setting that reduction by increasing rates to other customers as long as the increases did not result in rates increasing by more than the rate of inflation. Clearly this in violation of the Boston Gas PBR guidelines as well as being in conflict with the Department's precedent regarding discounts. *Id.* The Department must require the Company redraft its PCM Terms and Conditions in such a way as to eliminate this potential inequity as well as to assure that the provisions are clear, and consistent with those of Boston Gas Company's PBR rate design guidelines.

C. RATE DESIGN

The Company proposes several significant changes to the existing rate structure–elimination of the seasonality of rates charged residential and certain commercial and industrial customer classes, elimination of the existing Quasi-firm rates that have been closed since the Company's initial unbundling of rates in November, 1998, introduction of therm billing, and introduction of load factor CGAs, as discussed above. In the actual design of the Company's rates it relies on the Cost of Service Studies performed by Mr. Normand and Mr. Harrison. Mr. Normand performs the accounting or fully allocated embedded cost of service

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Department Letter Order dated February 28, 1995; and *Fitchburg Gas and Electric Light Company*, EC 95-19, Letter Order dated October 25, 1995. The Attorney General urges the Department to continue to apply this precedent in the Company's case not only as it relates to the PCM plan but also as it relates to the Company's proposed adjustment for the loss of approximately $90,000 in annual revenues due to the Company's agreement to discount its rates. Tr. 11, pp.1291-1295.

studies and Mr. Harrison the marginal cost studies. Exh. BG-17, Schs. PMN 3, 4, 5 and 8 (Accounting Cost Studies) and Exh. BG-20, Sch. JLH-4 (Marginal Cost Studies).

Beginning with the costs and revenues determined by Mr. Kruszyna (Exh. BG-6, Sch. JJK-2), Mr. Normand develops and applies allocation factors to spread costs to each of the Company's rate classes. Exh. BG-15, p. 9. As part of the allocation process, Mr. Normand produces cost studies that functionalize costs into the components related to the distribution or delivery function, customer charge function, and the production or supply function. Base rates are designed to recover costs related to the delivery and customer charge functions. Gas supply costs are recovered through the Company's CGA.

In designing the Company's proposed rates Mr. Normand begins with the fully allocated costs (the total revenue requirement is spread to each rate class) that incorporate equalized rates of return–in other words, each class's revenue requirement is determined based on that class generating the Company's proposed rate of return. Class revenue targets were developed in such a way that no class received an increase greater than 125% of the overall increase requested by the Company or 11% (125% of 9%) and no class would receive less than a 5% increase. *Id.* at 24. Low Income rates were set to have the customer charges discounted by 20% and usage rates 40% from the related undiscounted residential rates. The discount was spread to the other classes using rate base as the allocator.

Using the marginal cost studies as a guide, Mr. Normand set the customer charges for low use customers (residential, G-41 and G-51) at a level less than the capped increase of 11% and increased the large use classes (G-42, G-43, G-52, G-53 and T-54) at significantly higher percentage increases, using the rationale that the high use classes are not as sensitive to fixed charges as the lower use classes. Id. at 30-31. The seasonality of the current rates is maintained for the high use classes, and eliminated for the low use customer classes–because, according to Mr. Normand, most of the cost to serve the low use customers is fixed and does not vary with the season. *Id.* at 26.

Each class's revenue requirement that remains after the customer charge is established was used to set the volumetric component rates. For the existing blocked rates, block usage levels were established such that at least half the customers in each class, excluding zero use customers, were billed in the terminal or tail block. Tail block rates were set based on the marginal cost study and the remaining revenue requirement for each class was used to set the initial block rate. Id. at 27-28.

Mr. Normand provided bill impact analyses for each of the existing rate classes showing the impact on monthly customer bills for the peak, off peak and an average annual bill. Exh. BG-16, Sch. PMN-7. These analyses use, as comparison rates, the current distribution rates with the most recent CGA rates for the peak and off peak periods and compare these charges to the proposed distribution rates with CGA rates based on test year gas costs. To the extent that test year gas costs are not representative of the rate period costs to be included in the CGA at the time the proposed distribution rates are to be implemented, the bill impact analyses are somewhat misleading. The Company did provide a break down of bill impacts by component and season in response to a Department request. DTE-RR-52 (b). The component analyses show that proposed base distribution rate increases are significant–residential impacts range from over 27% in the off peak for non-heating customers (R-1) at the 50th percentile, an almost \$5.00/month increase to over 12% for heating customers (R-3) at the 50th percentile, an \$8.00/month increase. Low use commercial customers bill impacts are significantly steeper. High use customers, however, fare much better–experiencing bill decreases on an annual basis.

The Attorney General recognizes that these impacts are based on proposed rates and that Department decision may result in a substantially diminished revenue requirement and resultingly, lower bill impacts. Even with that potential dampening affect, the Attorney General urges the Department to require that the Company provide not only the equivalent of bill impact analyses provided in response to DTE-RR-52 (b) as part of its compliance filing but also to incorporate the CGA factors that will be either be in effect on February 1, 2002 or the proposed CGA factors for effect February 1, 2002 as ordered by the Department in this case in order that all parties may review the real bill impacts to the greatest and most realistic extent possible. Given the host of complex adjustments and issues associated with the proposed unbundled rates, the Attorney General also urges that the Department schedule a technical session for not earlier than one week from the date of the receipt of the Company's compliance filing so as to provide all parties with sufficient opportunity to review the Company's compliance filing. The Company has agreed to file unbundled and functionalized cost of service studies and should be required to file updated rate design worksheets as well as all supporting workpapers, calculations and explanations of all calculations supporting the filed rates, in addition to the bill impacts specified above.

D. INAPPROPRIATE ADJUSTMENTS

The Company proposed two adjustment in the rate design section of its filing–an increase in the number of Low Income customers and an increase in the revenue deficiency due to the removal of the test year LBRs. Exh. BG-22, p. 36, Exh. BG-15, p. 28, Exh. BG-17, Sched. PMN-6, Exh. DOER-1-19 (LBR increase in revenue requirement does not appear in Mr. Kruszyna's cost of service). Both these adjustments are inappropriate and should not have been buried in the Company's rate design sections. All cost of service and revenue deficiency calculations should be presented clearly by the Company's cost of service witness. The Company has withdrawn the LBR adjustment and normally the Attorney General would not discuss a correction on brief; but he must in this case in order urge the Department to put the Company on notice that this type of back door adjustment will not be condoned in the future.

Regarding the Low Income customer adjustment, the Department has not accepted this type of post test year adjustment[43] and should not in this case–there is no evidence that the rate year numbers of Low Income customers will be significantly different from those of the test year. The only data provided to support the adjustment shows that though there appears to be an increase in the number of low income customers since the end of the test year, there may be pattern where the number of low income customers may be the highest in the off peak months and drop off during the peak. DTE-RR-50. Although this phenomenon is unexplained, it indicates there is an ebb and flow of the number of low income customers. This conclusion is supported by the Company's statement that of the 104 new R-4 customers added since the test year 24 were no longer being served–clearly an indication of an ebb and flow. The Attorney General submits that the Company has not provided sufficient support for increasing the number of low income customers beyond the level of the test year and therefore this adjustment should be disallowed. Should the Department allow this adjustment, it must also increase the Company's test year revenues to account for the number of new customers added since the end of the test year.

[43] Department precedent does not generally permit post-test year adjustments to customer levels. " ... we typically decline to adjust test year revenues for post-test year changes that fall within the normal "ebb and flow" of customers. *Fitchburg Gas and Electric Light Company*, D.T.E. 99-118, pp. 16-17 (approving an adjustment for loss of customer post-test year as a significant loss outside the normal ebb and flow) and p. 22 (denying adjustment for new customers) (2001).

VI. COST OF CAPITAL

A. INTRODUCTION

The cost of service includes a return on rate base which provides the investors of the Company a return on the net investment that they have made in the Company. Exh. BG-6, Schedule JJK-1. The return compensates the debt holders, preferred stockholders, and common stockholders. *Id*., Schedule JJK-14. The dollar amount of the return is determined by multiplying the dollar amount of rate base by the overall cost rate of these different costs of capital weighted by the amount of each outstanding. *Id*. The different components of the overall cost of capital will be analyzed below.

B. THE DEPARTMENT SHOULD DETERMINE THE EFFECTIVE COST OF DEBT BASED ON THE AMOUNT OUTSTANDING AT THE END OF THE TEST YEAR

The Company proposes to determine the effective cost rate associated with each issue of debt based on the average amount outstanding over the term of each issue. Exh. BG-6, Schedule JJK-14, p. 4, note (1). For three of the issues, the First Mortgage bond due 3/1/2019, the Senior Note due 9/01/2020, and the Medium Term Note due 4/01/2004 this does not effect the cost rate because the balance outstanding will not change over the lifetime of the issue. *Id*. However, for two of the debt issues, the Medium Term Note due 9/30/2003 and the Senior Note due 11/15/2021, the cost rate is effected by the paydown of the outstanding balance over each note's term. *Id*.

The Department's precedent regarding the determination of the cost of debt is well settled. The rate is determined by adding the coupon to the annual amortization of issuance costs and dividing by the balance outstanding at the end of the test year. *Cambridge Electric*

Light Company, D.P.U. 92-250, pp. 136-137 (1993); *Berkshire Gas Company*, D.P.U. 92-210, p. 114 (1993); and *Massachusetts Electric Company*, D.P.U. 92-78, pp. 91-92 (1992). This methodology provides the best measure of the cost of the issue during the rate year, since it incorporates the most recent costs in the numerator and the most recent outstanding balances in the denominator. As Mr. Moul recognized with regard to the Medium Term Note due 9/30/2003:

> we're looking to reflect costs during the first year of the rate-effective period, and I felt that the forecast [for that period] was appropriate in that regard. Tr. 5, p. 604.

Equally, the denominator should reflect that which is expected to be outstanding for the rate year by using the year end balances of debt outstanding to determine the cost rate for the test year.[44]

The Company's proposed cost of debt calculation fails to comply with the Department's precedent, since it does not use the test year end balance of debt outstanding to determine the cost rate. Exh. BG-6, Schedule JJK-14, p. 4, note (1). Using, in the denominator, the average balance outstanding over the life time of the debt issue artificially inflates the effective interest rate that will be incurred during the rate year in this case.[45] The calculations that correct the errors in Mr. Moul's schedules by using the year-end balances of debt outstanding to determine the effective cost rate are found in the Exhibit AG-RR-37. The Department should use these cost rates for the Medium Term Note due 9/30/2003 and the Senior Note due 11/15/2021.

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[44] The Department's use of a capital structure and cost rates based on test year end balances is also consistent with the Department's use of test year-end rate base. Exh. BG-5, p.5.

[45] Equally, the Department does not use the average balance of net plant over its remaining life, since this would effectively cut in half the rate base used to determine base rates.

C. THE COST OF COMMON EQUITY

The cost of the Company's common of equity is not readily measured in the manner that its costs of debt and preferred stock are. The Company sponsored the testimony of Mr. Paul Moul regarding the cost of common equity. Exh. BG-10, 11, and 12. Mr. Moul performed two basic analyses of the cost of equity -- a Discounted Cash Flow analysis ("DCF") and a Risk Premium analysis and supplemented those analyses with a Capital Asset Pricing Model analysis ("CAPM") and a Comparable Earnings analysis. *Id*., pp. 3- 4. Since the Company does not issue common stock that is publicly held or traded, it is impossible to determine the market cost of equity for the Company's stock using any market based approach. *Id*. Therefore, Mr. Moul chose a group of companies that he deemed comparable in investment risk to Berkshire Gas Company and performed his cost of equity analyses on this group of companies to determine a cost of common equity for Berkshire Gas. *Id*.

As will be discussed below, Mr. Moul's methodologies are fundamentally flawed. His cost of equity analyses grossly overstate the cost of capital for the barometer group as well as the Company. However, appropriate corrections to his analyses, as are discussed below, result in a cost of common equity of 9.84 percent. Therefore, the Department should use a cost of common equity no higher than 9.84 percent to determine the Company's revenue requirement in this case.

D. MR. MOUL'S DISCOUNTED CASH FLOW ANALYSIS OVERSTATES THE COST OF COMMON EQUITY FOR THE COMPARISON GROUP

1. INTRODUCTION

Mr. Moul performed a DCF analysis of a group of comparison companies that he deemed were comparable to the Company in terms of their investment risk. Exh. BG-10, pp. 27-37. The economic theory underlying the application of the DCF analysis is that the market price that an investor is willing to pay for a share of common stock is equal to the present value of the cash dividends and the proceeds from the sale of the investment when the investor sells the stock. *Id*. p. 28. The DCF theory can be modeled by the following equation:

$$k = \frac{D}{P} + g$$

where k = the investors' required return on common equity;

D = the dividend per share paid in the next period;

P = the current market price per share of the common stock; and

g = the investors' mean expected long-run growth rate in dividends paid per share. Exh. BG-11, Appendix E. Some of the components of the model are easily measured such as the current price and the current dividend in effect during the period. However, the investors' expectations of the growth in dividends over the next year and over the rest of the investors' holding period are not directly measurable. Each of these components to the model will be discussed below.

2. THE DIVIDEND YIELD

The dividend yield component of the DCF model is determined by dividing the indicated dividend by the current market price of the stock.[46] Exh. BG-10, pp. 29-30. Using the dividend yield based on the information of one point in time will result in a volatile yield that will be susceptible to the peculiarities of "one day" events that might effect the market. *Id*. To avoid any abnormalities associated with using "one day" information, it is appropriate to use the average of several months of dividend yields. *Id*.

Mr. Moul provided the most recent twelve months of dividend yield information for this comparison group's common stock in his response to Exh. AG-RR-10 [Exh. BG-12, p. 13, Schedule 7, Update]. From this information, the most recent six month dividend yield average is 4.72 percent while the most recent twelve month average is 4.72 percent. *Id*. Based on these yields, a 4.72 percent dividend yield adjusted for the growth rate discussed below is an appropriate basis for the Department to use in its analysis of the DCF model.

3. GROWTH RATE

The growth rate used in the DCF model is the investors' mean expected long run growth rate in dividends paid per share. Exh. BG-11, Appendix E, p. E-9 ("viewed in its infinite form, the DCF model is represented by the discounted value of an endless stream of growing dividends."). Since it is impractical to measure all of the investors' expectations regarding their growth rate estimates, it is necessary to use proxies for those expectations. These proxies include historical and forecasted measures of dividends, earnings, and book value per share growth rates as well as the growth rates from retained earnings. Mr. Moul provided some of

46 The indicated dividend is determined by annualizing the level of the current quarterly dividend per share being paid.

these proxies for the comparison group.

	Ten-Year Historical	Five-Year Historical	Five-Year Projected
Dividends Per Share	3.15%	3.25%	2.78%
Earnings Per Share	2.35	2.15	7.54 [47]
Book Value Per Share	4.00	4.23	6.83
Growth From Retained Earnings			7.20

Exh. AG-RR-10, [Exh. BG-12, p. 1, Schedule 8, Update.]

As Mr. Moul has done time and again, he has pulled his DCF growth rate estimate out of the air, choosing the highest available estimates, ignoring all historical data, and explicitly throwing out any negative data to determine his averages. The upward bias in his DCF growth rate estimate is obvious. His growth rate estimate for the comparison group of 7.00 percent is 375 basis points above the historical dividend growth rate and 422 basis points above the projected dividend growth rate. *Id*. This comparison by itself shows how inflated his estimate is. Furthermore, his chosen methodology of basing the DCF growth rate estimate on short-term earnings projections has not stood the test of time. In the Company's last base rate case D.P.U. 92-210, Mr. Moul estimated that the growth rate for a similar comparison group would be 5.5 percent when in fact the dividends, earnings and book value growth rates were all less than four percent and below over the last ten years.[48] *Compare Berkshire Gas Company,*

[47] The earnings per share five year forecast is the simply average of those statistics found on Exh. AG-RR-10 [Exhibit BG-12, p. 15, Schedule 9 Update]

[48] Note that these measures of growth occurred during one of the longest economic expansions in U.S. history.

D.P.U. 92-210, p. 125 (1993) and Exh. AG-RR-10, [Exh. BG-12, p. 1, Schedule 8, Update.] . Furthermore, to put his estimate in perspective of the economy as a whole, Mr. Moul short-run earnings growth rate estimate of 7 percent for his gas distribution companies is 1.50 percent higher then the 5.5 percent long-run consensus growth rate forecast of the overall economy. Exh. AG-RR-7, p. 14, ("Nominal G.P. Consensus" is 5.5% for 2003-2007 and 5.4% for 2008-2012) .

Clearly, Mr. Moul's estimates based on the short-term earnings per share forecasts is inflated, and should be rejected by the Department. Instead, the Department should base its DCF growth rate on more reasonable growth rate proxies which are inline with historical measures as well as reasonable long-run forecast measures of growth. For instance, the Department should consider that the average of the five-year historical and forecasted growth rates in dividends per share yields a 3.02 percent growth rate. [(3.25% + 2.78%) / 2]. Exh. AG-RR-10, [Exh. BG-12, p. 1, Schedule 8, Update.] Averaging the five year historical and forecasted growth rates in earnings per share yields a 4.85 percent growth rate. [(2.15% + 7.54%) / 2]. *Id*. And averaging the five year historical and forecasted growth rates in book value per share yields a 5.53 percent growth rate. [(4.23% + 6.83%) / 2]. *Id*. Given these averages, a 5.0 percent DCF growth rate would be a reasonable estimate of the DCF growth rate that investors expect. Furthermore, it is certainly more inline with the 5.5 percent long-run growth rate that is forecast for the economy. Exh. AG-RR-7, p. 14.

4. DCF SUMMARY

The Department should reject Mr. Moul's proposed DCF analysis for the reasons discussed *supra*. As was discussed in the Dividend Yield section, an appropriate proxy for the current dividend yield based on the latest information available is 4.72 percent. An appropriate

DCF growth rate is 5.0 percent. Using these parameters, a DCF cost of common equity can be determined:

	Growth Rate at 5.0%
Current Dividend Yield	4.72%
DCF Dividend Yield	4.84
Growth Rate	5.00
DCF Cost of Common Equity	9.84%

This DCF analysis provides a reasonable cost of equity estimate for Mr. Moul's comparison group.

E. MR. MOUL'S CAPITAL ASSET PRICING MODEL ANALYSIS MUST BE REJECTED BY THE DEPARTMENT

Mr. Moul performed a Capital Asset Pricing Model analysis to estimate the cost of equity for his comparison group. Exh. BG-10, pp. 42-47 and Exh. BG-11, Appendix H. The Department should reject Mr. Moul's CAPM analysis based not only on his poor application of the model in this case, but also for the reason that the assumptions underlying the CAPM depart so substantially from the real world that they make the model totally useless for purposes of determining the cost of common equity for a utility company.

1. INTRODUCTION

The CAPM is a risk premium approach used to determine the cost of assets. *Id.* Like other risk premium approaches, it is based on the assumption that investors require a higher return on their investment for them to hold assets of greater risk. *Id.*. The CAPM approach breaks the total risk of an asset into two components, systematic risk and unsystematic risk. *Id.*, p. Appendix H, p. H-1. Systematic risk represents the variability of the return on an investment associated with the effect of economy-wide forces (e.g. information and interest levels). *Id.* Unsystematic risk, on the other hand, represents the risk associated with asset specific risks (e.g. risks that are specific to a particular company like industry competition and the quality of a company's management). *Id.* Portfolio theory assumes that an asset is evaluated in the context of a well-diversified portfolio where the unsystematic risks associated with individual assets cancel each other out. *Id.* Under the same theory, since unsystematic risk can be diversified away by holding a well diversified portfolio, the only risk the CAPM model use should be concerned with is the amount of systematic risk associated with the asset. *Id.*

The CAPM measures the systematic risk of an asset with factor known as beta. *Id.*, pp. H-2 - H-3. The Model defines the beta value of all assets, on average, as equal to 1.0. *Id.* In the Model, an asset with a beta of 1.0 will have a return which will have variations equal to the variability of the returns of the market as a whole. *Id.* The price of an asset with a beta of 1.0 will increase by 10 percent when the market value as a whole increases by 10 percent. *Id.* Conversely, the asset's price will decrease by 10 percent when the market value goes down by 10 percent. *Id.* Furthermore, the price of an asset with a beta of 1.5 will increase by 15 percent when the market increases 10 percent and decrease 15 percent when the market decreases 10 percent. *Id.* If the beta is 0.5, the asset's price will increase 5 percent when the market increase 10 percent, and it will decrease by 5 percent when the market decreases by 10 percent. *Id.*

The CAPM theory provides a formula to determine the return on the asset that is required by the market. *Id.* The formula is as follows:

$$r = rf + b \times rp$$

where r = the market required return on the asset;

rf = the return on risk-free investments;

b = the beta of the asset; and

rp = the expected difference between the return on the market as a whole and the return on the risk-free asset.

Id. This is the formula that Mr. Moul used to perform his CAPM analysis in this case.

2. The Assumptions Underlying The Capital Asset Pricing Model Are So Unrealistic That The Model Cannot Be Used To Determine The Cost Of Capital For The Company

The CAPM theory and the formula derived from the theory are based on many assumptions, as will be discussed below. Although some of these underlying assumptions of the CAPM are true in the real world, several of them just do not hold true for the application of the Model in the case of an investment in the comparison group's common stock. Without these assumptions that are fundamental to the CAPM, the use of the Model is inappropriate, and must be rejected by the Department.

The Department has found that the assumptions underlying the CAPM are too "heroic" to make the application for a utility stock useful. *Boston Gas Company*, D.P.U. 96-50, p. 125 (1996); *Berkshire Gas Company*; D.P.U. 92-210, pp.148-150 (1993); *Boston Gas Company*, D.P.U. 92-78, p. 113 (1992); *Boston Gas Company*, 88-67 (Phase I), p. 184 (1988); *Commonwealth Electric Company*, D.P.U. 956, pp. 54-55 (1982). Specifically, the Department found in Commonwealth Electric Company that the following assumptions are too unrealistic for anyone to seriously consider:

(1) investors can borrow and lend an unlimited amount of money at a risk-free

rate;

(2) investors evaluate equity/security portfolios according to the means and standard deviations of portfolio returns;

(3) there are *no* income taxes; and

(4) investors are "single period expected utility of terminal wealth maximizers" -- that is a 100 percent liquidating dividend is paid at the end of the period.

Id., p 54. [emphasis added]. Clearly, the assumptions of a world with unlimited investor borrowing capacity and no income taxes is one that investors would find highly desirable, but simply does not exist. Furthermore, the assumptions try to fit all investors into one neat package to conform to the Model requirements. The requirements that investors evaluate their portfolio returns and liquidate their investments at the end of the holding period obviously cannot contain the many different investors with many different analysis techniques and investment requirements into one model. Mr. Moul's analysis never attempts to address any of these fundamental problems with these assumptions of the Model. For this reason alone, the Department should reject the use of the CAPM analysis as a methodology for determining the cost of equity for utilities as it has done in the past. *Id*.

Mr. Moul's CAPM analysis is also flawed in its application. Mr. Moul's application of the CAPM assumes that all investors have a 30-year investment horizon, since he used 30-year U.S. Treasury Bonds as the basis for his analysis. Exh. BG-10, p. 45.[49] Of course other investors have infinitely many investment horizons that will cause different return requirements. For instance, if one assumes that investors had a five-year investment horizon,

[49] In fact, given the recent announcement by the federal reserve that it will no longer be issuing the 30-year U.S. Treasury Bonds, Mr. Moul's whole CAPM analysis based on the those bonds should be rejected by Department.

then their CAPM required return would be as follows:

CAPM Cost of Equity For
Five-Year Investment Horizon

Five-Year Yield	4.66%
Equity Risk Premium Over Five-Year Yields	8.20
Beta	0.72
Required Cost of Equity	10.57%

See Exh. AG-RR-10, [Exhibit BG-12, p. 24, Schedule 12, Update] and AG-6, Table 9-2. Furthermore, if one assumes that investors had a thirty day investment horizon, then their CAPM required return would be as follows:

CAPM Cost of Equity For
Thirty-Day Investment Horizon

Thirty Day Yields	2.50%
Equity Risk Premium Over Thirty-Day Yields	9.10
Beta	0.72
Required Cost of Equity	9.05%

Id.

Thus, for any investors short of the thirty year investment horizon used by Mr. Moul, it is clear that their required returns are significantly less than the 12.69 percent return that he uses as the recommendation from his CAPM analysis.

For all of the above reasons, the Department should reject Mr. Moul's CAPM analysis.

F. MR. MOUL'S COMPARABLE EARNINGS ANALYSIS SHOULD BE REJECTED BY THE DEPARTMENT

Mr. Moul also performed a Comparable Earnings analysis. Exh. BG-10, pp. 47-51and Exh. BG-11, Appendix I. He bases this comparable earnings analysis on certain stock indicators used by *Value Line Investment Survey*. Exh. BG-10, pp. 49-50. The use of the Comparable Earnings approach has been resoundingly rejected by the Department time and time again. Boston Gas Company, D.P.U. 96-50, pp. 131-132 (1996); Cambridge Electric Light Company, D.P.U. 92-250, pp. 160-161 (1993); Bay State Gas Company, D.P.U. 92-111, pp. 280-281 (1993); Berkshire Gas Company, D.P.U. 92-210, p. 155 (1993); and Berkshire Gas Company, D.P.U. 905, pp. 48-49 (1982). For instance, in D.P.U. 905, the Department specifically rejected Mr. Moul's use of the Comparable Earnings Approach because it found the results unreliable since the earned return on common equity did not necessarily equal the companies' cost of capital. and *Berkshire Gas Company*, D.P.U. 905, pp. 48-49 (1982) citing Boston Edison Company, D.P.U. 19991, p. 56 (1979). Mr. Moul has provided not reason in this case for the Department to change its well-founded precedent. Therefore, the Department should reject Mr. Moul's Comparable Earnings analysis, since its results are unreliable.

G. MR. MOUL'S RISK PREMIUM ANALYSIS SHOULD BE REJECTED BY THE DEPARTMENT

Mr. Moul also provided his usual Risk Premium Analysis. Exh. BG-10, pp. 37-42 and Exh. BG-11, Appendix G. Although he represents this methodology as a separate and distinct analysis from the CAPM analysis, it is essentially the same analysis. The cost of equity capital is equal to the yield on utility bonds plus an equity risk premium. *Id*. His risk premium analysis substitutes utility bonds for U.S. Treasury bonds and he substitutes the Standard and

Poors utility index for the stock market return. *Id*.

The Department has reviewed and rejected Risk Premium analyses like Mr. Moul's may times before. See *Boston Gas Company*, D.P.U. 96-50, p. 128; *Massachusetts Electric Company*, D.P.U. 95-40, p. 97 (1995); *Boston Gas Company*, D.P.U. 93-60, p. 261 (1993); *Bay State Gas Company*, D.P.U. 92-111, pp. 265-266; *Berkshire Gas Company*, D.P.U. 92-210, pp. 138-139 (1993); and *Berkshire Gas Company*, D.P.U. 90-121, p. 171 (1991) Each time the Department has found that the risk premium approach overstates the amount of company-specific risk and, therefore, overstates the cost of equity. *Id*. The Company has provided no new analyses and no new argument to change this simple fact. Therefore, the Department should reject Mr. Moul's Risk Premium analysis, here as it has done in all of the other cases. *Id*.

H. MR. MOUL'S RISK ANALYSIS AND RISK ADJUSTMENTS SHOULD BE REJECTED BY THE DEPARTMENT

Mr. Moul labors hard in this case to find reasons to increase his cost of equity recommendations by creating brand new adjustments to the results of analyses based on specific cost or risk factors that he now deems worthy of measuring. These adjustments increase the cost of equity for his comparison group, and ultimately for the Company. These adjustments include his market to book ratio adjustment applied to his DCF analysis which inflates his DCF results by 95 basis points. Exh. BG-10, pp. 34-37. They also includes his leveraging and unleveraging the betas used in his CAPM analysis which inflates the results of the CAPM by 134 basis points or 1.34 percent [(0.72 - 0.59) x 10.34%]. Exh. BG-10, pp. 45-46. Yet, Mr. Moul ignores what is probable the most important single factor that investors consider when investing in the companies in the comparison group -- the non-utility businesses that the companies are involved in that increase the risk for these companies.

The Department is setting rates for the regulated gas distribution business. Tr. 5, pp. 565-566. Therefore, the allowed return on common equity should reflect only the market required return for that business. However, as each of the companies in Mr. Moul's comparison group is invested in other non-utility businesses, their costs of equity for the overall operations of the corporations will diverge from that of the utility operations. Whether the non-utility businesses are oil and gas exploration or power generation marketers, these other businesses have higher required returns on common equity. The Value Line Investment Survey explicitly recognizes the higher risks and expected return requirements associated with these other businesses in warning customers not to invest in those companies with such businesses:

> Gas utilities have traditionally been considered defensive, income oriented stocks. But that picture is changing somewhat as distribution companies expand into non-regulated businesses. It has become increasingly important to examine stocks on an individual basis in this industry before making a commitment. For as companies move into different activities, there will likely be greater variances in the total-return performances of these issues with different levels of risk.
>
> Risk-averse investors focused on income should stick with those companies in this industry that remain in the regulated gas-distribution business. Distributors that are expanding into non-regulated businesses do have better growth potential, but their earnings and stock prices are becoming more volatile. Also, the dividend yields are likely to drop over time, as these companies retain more earnings to invest back into their operations.

Tr. 5, pp. 656-657.

Yet, Mr. Moul completely ignores this critical factor. Why ? Because to make an adjustment to compensate for these risks would lower the cost of capital for the regulated gas distribution business. The clear bias in Mr. Moul's analysis and adjustments by themselves should cause the Department to reject his cost of capital recommendations.

I. RECOMMENDATIONS

For all of the above reasons the Department should reject the recommendations regarding the cost of capital of Mr. Moul. Instead, the Department should determine the cost of common equity based on a DCF analysis that results in a 9.84 percent allowed return. See Section 2, supra.

J. DEPRECIATION EXPENSE

The Company sponsored the testimony of James H. Aikman regarding the depreciation accrual rates for the Company's plant in service. Exh. BG-13 and Exh. BG-14. Mr. Aikman performed an actuarial study of the useful lives and a study of the net salvage values of each plant account. *Id*. (See Study date September 11, 2000.) As will be discussed below, several of Mr. Aikman's life analyses are flawed and should be rejected by the Department.

1. ACCOUNT 305 – MANUFACTURED GAS PRODUCTION PLANT STRUCTURES AND IMPROVEMENTS

Mr. Aikman recommends using a 40 year life for Account 305 – Structures and Improvements and 34 years for the new Whately LNG Facility (the "non-Whately Facilities"). *Id*. p. 6 and Tr. 10, pp. 1099-1108. Mr. Aikman based the non-Whately life on the actuarial studies while he calculated the life for the Whately Facility by estimating the average service life of the individual units of property associated with that facility. *Id*.

Mr. Aikman's analysis mixes and matches service life estimates to artificially (an inappropriately) reduce the average service life of the Whately LNG Facility. Mr. Aikman relies on the overall 40-year actuarial life analysis results of all of the units of property at the old non-Whately plant in Account 305 as the starting point of his analysis of the Whately Facility. *Id*.

Then, he averages down that number by identifying certain units of property that have shorter lives to reduce the overall average for the new facility. *Id.* Of course, to be consistent, if Mr. Aikman is going to rely on the overall 40 year life of all of the units of property for the non-Whately facilities, he must use the whole of the account at 40 years and apply it to all of the units of property at the new Whately Facility. Therefore, the Department should reject Mr. Aikman's 34 year life estimate for the Account 305 – Whately LNG Facilities and instead use the 40 year life as he has for the Company's non-Whately facilities in that account.

2. ACCOUNT 319.10 – GAS MIXING EQUIPMENT – WHATELY LNG FACILITY

Mr. Aikman recommends using a 24 year life for Account 319.10 – Gas Mixing Equipment associated with the Whately LNG Facility. *Id.* Here again, Mr. Aikman's analysis mixes and matches service life estimates to artificially and inappropriately reduce the average service life of the Whately LNG Facility. *Id.* Mr. Aikman relies on the overall 25-year actuarial life analysis results of all of the units of property at the old non-Whately plant in Account 319.10 as the starting point of his analysis of the Whately Facility. *Id.* Then, he averages down that number by identifying certain units of property that have shorter lives to reduce the overall average for the new facility.[50] *Id.* Again, to be consistent, if Mr. Aikman is going to rely on the overall life of all of the units of property for the non-Whately facilities, he must use that whole number of 25 years and apply it to all of the units of property at the new Whately Facility. Therefore, the Department should reject Mr. Aikman's 24 year life estimate for the Account 319.10 – Whately LNG Facilities and instead use the 25 year life as he has for the Company's

[50] Certainly, one could find units of property at these sites that have useful lives greater than 40 years. Failure to specifically identify these and include them in the calculation bias Mr. Aikman's analyses towards shorter lives.

non-Whately facilities in that account.

3. ACCOUNT 367 – MAINS

The Company proposes to use a 60 year life for Account 367 – Mains. *Id.*, p. 9. While the Attorney General does not recommend a change in the recommended life at this time, he does recommend that the Department order Berkshire Gas Company as well as all the other gas distribution companies in this state to analyze their mains and services by material type (e.g. uncoated steel, coated steel, and plastic) so that the Department can have a better analysis of the lives of each material and their effect on the overall weighted average life of the mains and services accounts. The Attorney General believes this is important information for the Department to acquire. The results of more recent studies indicate that the new materials are having a dramatic effect on the average service life, as would be expected with materials like coated steel and plastic. Early retirements of uncoated pipes have significantly decreased service life estimates. New materials seems to be reversing the trend. Therefore, the Department should order the Company's account for the lives of the various material types of mains and services separately. This would result in a more accurate depreciation rate.

4. ACCOUNTS 380 – SERVICES

The Company proposes to use a 38 year average service life for Account 380 – Services. *Id.*, p. 10. This average service life is based on the Company's recent actuarial analyses. *Id.* However, the 38 year average service life for Account 380 – Services has been dramatically impacted by the defective materials used to make the services that the Company installed. As Mr. Aikman clearly states:

> One consideration in the process of deciding whether to replace a service is the Company practice of retiring any service which is older than

45 years.

Id. The Company conceded that this early retirement program for services was as the result of the Company installing services that were made with defective materials. Exh. AG-14-3 and Exh. AG-RR-43. Specifically, the Company found determined that the coating on the pipes was failing. *Id*. However, after the Company determined the defect in the materials in the services, the Company failed to do anything to recover or limit the replacement cost of these defective products. *Id*.

Customers should not be burdened with the costs associated with the imprudent acts of the utility.

> For costs a company seeks to recover in rates, the expenditures must be prudently incurred, and the resulting plant must be used and useful in providing service to ratepayers. *Fitchburg Gas & Electric Light Company*, D.T.E. 98-51, at 12 (1998), *Boston Gas Company*, D.P.U. 93-60, at 24 (1993). A prudence review must determine whether the utility's actions, based on all that it knew or should of known at the time, were reasonable and prudent in light of the circumstances that then existed. D.T.E. 98-51, at 12. A determination of reasonableness and prudence may not properly be made on the basis of hindsight judgments, nor is it appropriate for the Department merely to substitute its own judgment for the management of the utility. *Attorney General v. Department of Public Utilities*, 390 Mass. 208, 229 (1983). A prudence review must base its findings on how a company reasonably should have responded to the particular circumstances and whether the company's actions were in fact prudent in light of all the circumstances that were known or reasonably should have been known at the time the decision was made. DPU. 98-51 at 12.

Boston Edison Company, D.T.E. 98-119, p. 62 (1999). Clearly, the Company's failure to even attempt to recover the costs associated with these defective services is an imprudent action for which the Company should not be allowed compensation.

The Department should order the Company to prepare for its next rate case a specific study of the costs and lives of these defective services in order to determine their effects on the Company's costs and on the Company's rates. In the interim, the Department should use a proxy 45 year average service life for the Account 380 plant in order to ensure that customers are not paying for the costs of these defective products. *See Fitchburg Gas & Electric Light Company*, D.P.U. 98-51, pp. 87 (1998) (the latest depreciation study decided by the Department for the 45 year life estimate.)

VIII. CONCLUSION

The Attorney General urges the Department to adopt the recommendations made throughout this brief.

Respectfully Submitted,

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